DER-CAM DECISION SUPPORT TOOL FOR DECENTRALIZED ENERGY SYSTEMS

ANALYTICS | PLANNING | OPERATIONS

DER-CAM User Manual

Full DER Web Optimization Service: a project partly financed by the U.S. Department of Energy

DER-CAM Version 4.4.1.3

Interface Version 1.4.1.0

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Contents

I. Introduction to DER-CAM Web Optimization

This document contains the user manual for accessing DER-CAM using the Web Optimization Interface in its current version, 1.4.1.0, and gives examples of its functionalities and options.

What is DER-CAM?

DER-CAM (Distributed Energy Resources Customer Adoption Model) is a decision support tool for investment and planning **distributed energy resources (DER)** in buildings and microgrids. The problem addressed by DER-CAM is formulated as a mixed integer linear program (MILP) that finds optimal DER investments while minimizing total energy costs, carbon dioxide (CO_2) emissions, or a weighted objective that simultaneously considers both criteria.

A **microgrid** is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid and operate both in grid-connected or island-mode. Distributed Energy Resources are commonly defined as a set of locally available technologies and strategies with potential to make energy use more efficient, accessible, and environmentally sustainable. These solutions include power generation and combined heat and power (CHP) using conventional fuel-fired technologies, but also renewable technologies such as PV, and energy management strategies such as demand response, load shifting, and peak-shaving. Storage technologies, including stationary storage, mobile storage in the form of electric vehicle batteries, as well as thermal storage tanks, are also considered DER.

To optimize DER investments DER-CAM chooses the portfolio of technologies that maximize economic and/or environmental benefits, based on optimized hourly dispatch decisions that consider specific site load, price information, and performance data for available equipment options. The output results are simultaneously comprised of the optimal technology portfolio as well as the corresponding dispatch that justifies the investment.

<u>Key inputs to the model are:</u>

1. customer's end-use hourly load profiles (typically for space heat, hot water, natural gas only, (electric) cooling, (electric) refrigeration, and electricity only), defined over three day-types: week days, weekend days, and peak/outlier days

2. customer's default electricity tariff, natural gas prices, and other relevant price data

3. capital costs, operation and maintenance (O&M) costs, and fuel costs of the various available technologies, together with the interest rate on customer investment and maximum allowed payback

4. basic technical performance indicators of generation and storage technologies including the thermal-electric ratio that determines how much residual heat is available as a function of generator electric output

Output determined by DER-CAM

1. optimal capacity of on-site DER

2. optimized strategic dispatch of all DER, taking energy management measures into account

3. detailed economic results, including costs of energy supply and all DER-related costs

DER-CAM Web Optimization

DER-CAM Web Optimization refers to the service that integrates the DER-CAM model with a web-based user interface. This online platform facilitates the handling of input data and optimization parameters for multiple projects prior to running the algorithm on a dedicated server hosted at LBNL. It also enables graphical visualization of results and exporting them via e-mail.
To simplify, the *DER-CAM Web Optimization* will simply be referred to as DER-CAM throughout this document.

II. Getting started with DER-CAM

In this section we will go through the very first steps to quickly get logged in, create your first project and start using DER-CAM.

Creating a DER-CAM model can be done quickly using the following five steps:

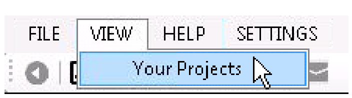
1. Go to ***https://microgrids2.lbl.gov*** and enter your user credentials. Click on "Login" and on the following page click on "Full DER-CAM Optimization Service".

2. After the connection to the interface is established, a user agreement will appear. Please review the conditions and click "Accept" to proceed or "Deny" to reject and exit the application.

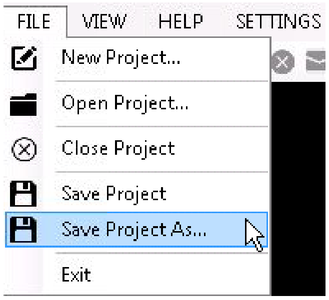
Note: At this point only advanced DER-CAM users are given a private storage folder for their DER-CAM projects and customized versions. This can be accessed via the "Advanced user Login" button. For standard DER-CAM access all files are currently kept in a common user folder and only the main stable version of DER-CAM is offered.

3. On the main window (Figure 1) click on "New Project…" under "Start" to create a new DER-CAM project. Alternatively you may click the button on the toolbar or select "New Project" from the FILE menu.

Note: To open an existing project click on "Open Project…" under "Start", use the button, or select "Open Project" from the FILE menu. To view and manage all your projects (rename, delete), click on the VIEW menu and select "Your Projects".



TIP: To create quickly a new project from an existing one, select "Save Project As…" in the File menu and enter a name for your new project.



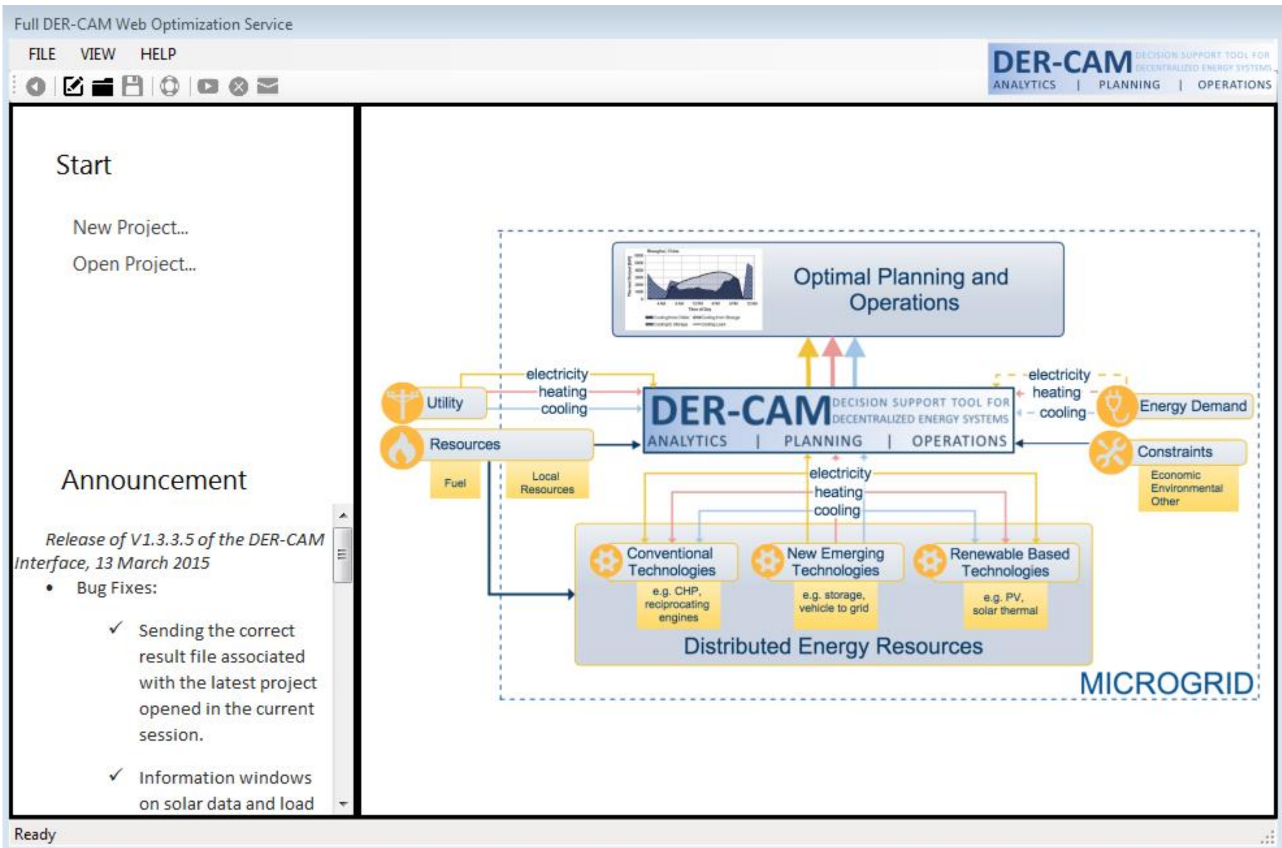


Figure 1: Start Window

4. After selecting "New Project" the New Project Window will appear (see **Error! Reference source not found.**). Enter a name for your project and select the DER-CAM version you want to use. By ticking the checkbox under it, you will enable the use of DER-CAM databases containing building load and solar radiation profiles. Additional information on the data contained in the databases is available by clicking the respective "Information" box (Figures 3 and 4).

Once the data is loaded, you may browse through it by clicking on each of the available tabs (electricity only, electric cooling, electric refrigeration, space heating, water heating, and natural gas only). Use the slider on the right to change the day-type profile being displayed. The three considered day-types consist of the average weekday, the average weekend day, and a peak day which could be defined as a day with an irregular load profile; examples include holidays or days with a very high demand that may be needed to properly capture power demand costs. The different lines shown load profile plots correspond to each month of the year.

<u>Note</u>: You can view and modify your project settings at any point during your session by clicking on the SETTINGS menu.

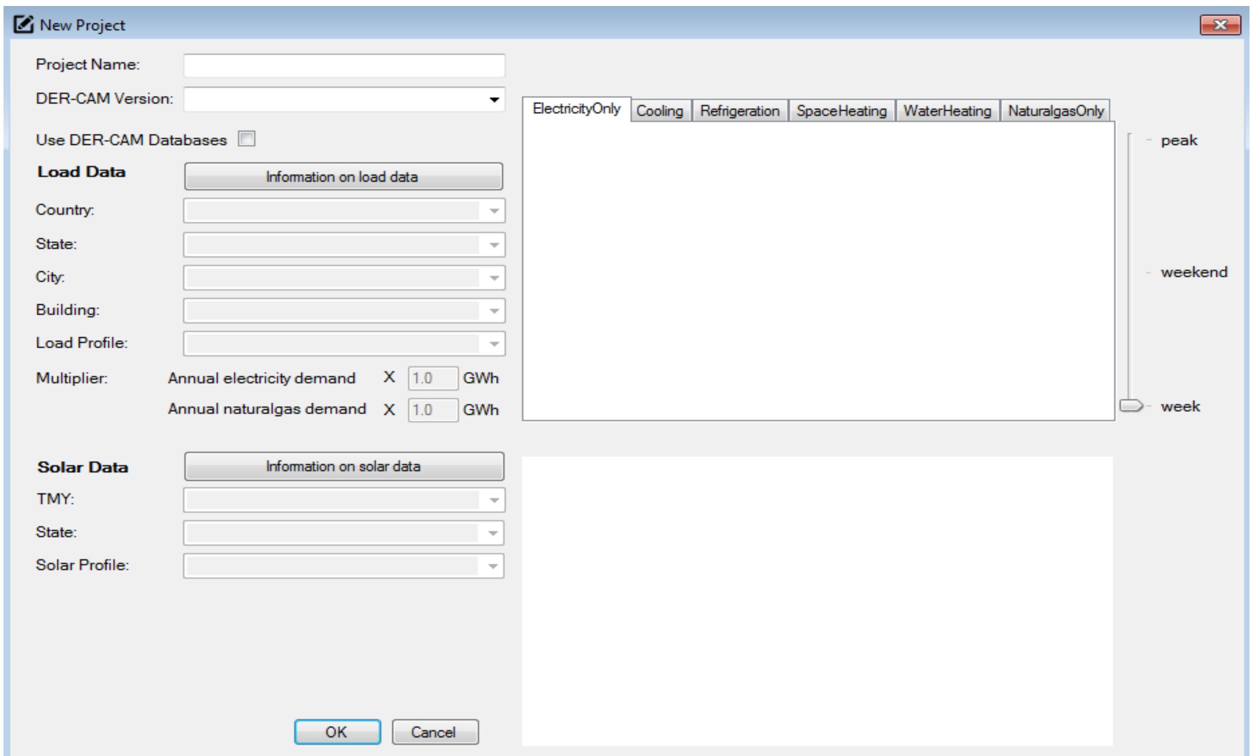


Figure 2: New Project Window

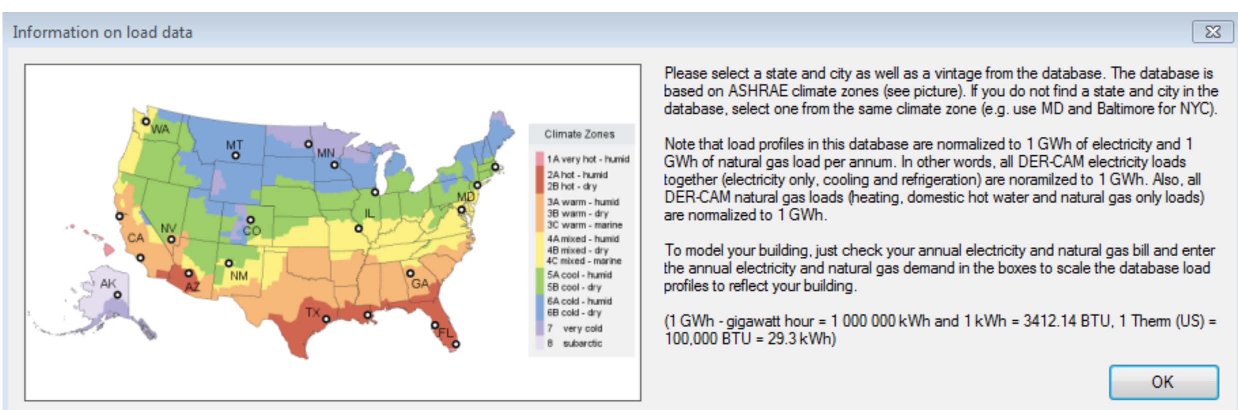
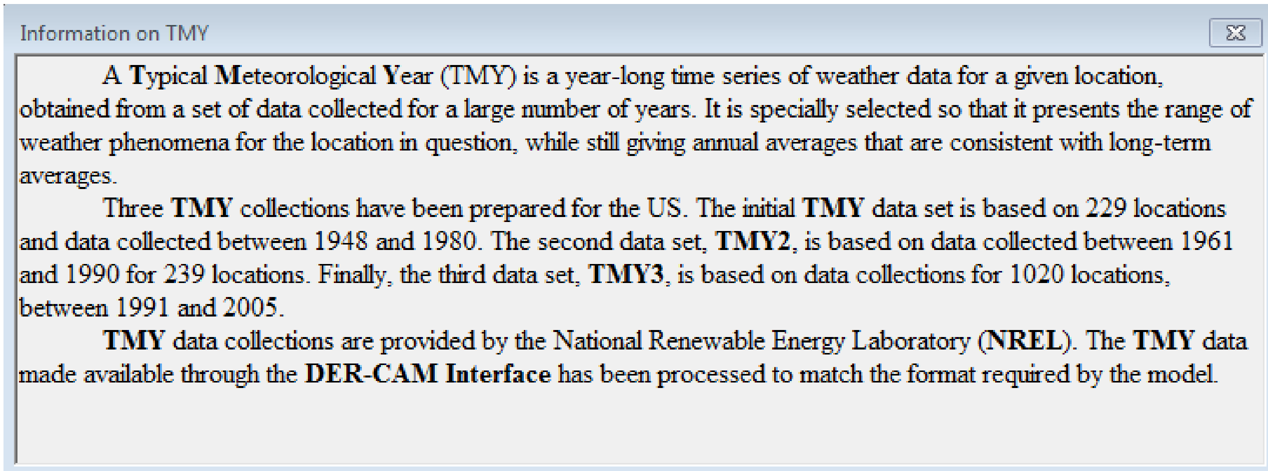


Figure 3:Information on Load data window



Information on TMY

A **T**ypical **M**eteorological **Y**ear (TMY) is a year-long time series of weather data for a given location, obtained from a set of data collected for a large number of years. It is specially selected so that it presents the range of weather phenomena for the location in question, while still giving annual averages that are consistent with long-term averages.

Three **TMY** collections have been prepared for the US. The initial **TMY** data set is based on 229 locations and data collected between 1948 and 1980. The second data set, **TMY2**, is based on data collected between 1961 and 1990 for 239 locations. Finally, the third data set, **TMY3**, is based on data collections for 1020 locations, between 1991 and 2005.

TMY data collections are provided by the National Renewable Energy Laboratory (**NREL**). The **TMY** data made available through the **DER-CAM Interface** has been processed to match the format required by the model.

Figure 4: Information on Solar data window

5. After creating your project you will be presented with the main screen shown in Figure 5. We will refer to this screen in the next sections as the "Pie", where each of the six segments contains different parameters and input data required to run DER-CAM. Returning to this window can be done at anytime by clicking on this icon in the toolbar.

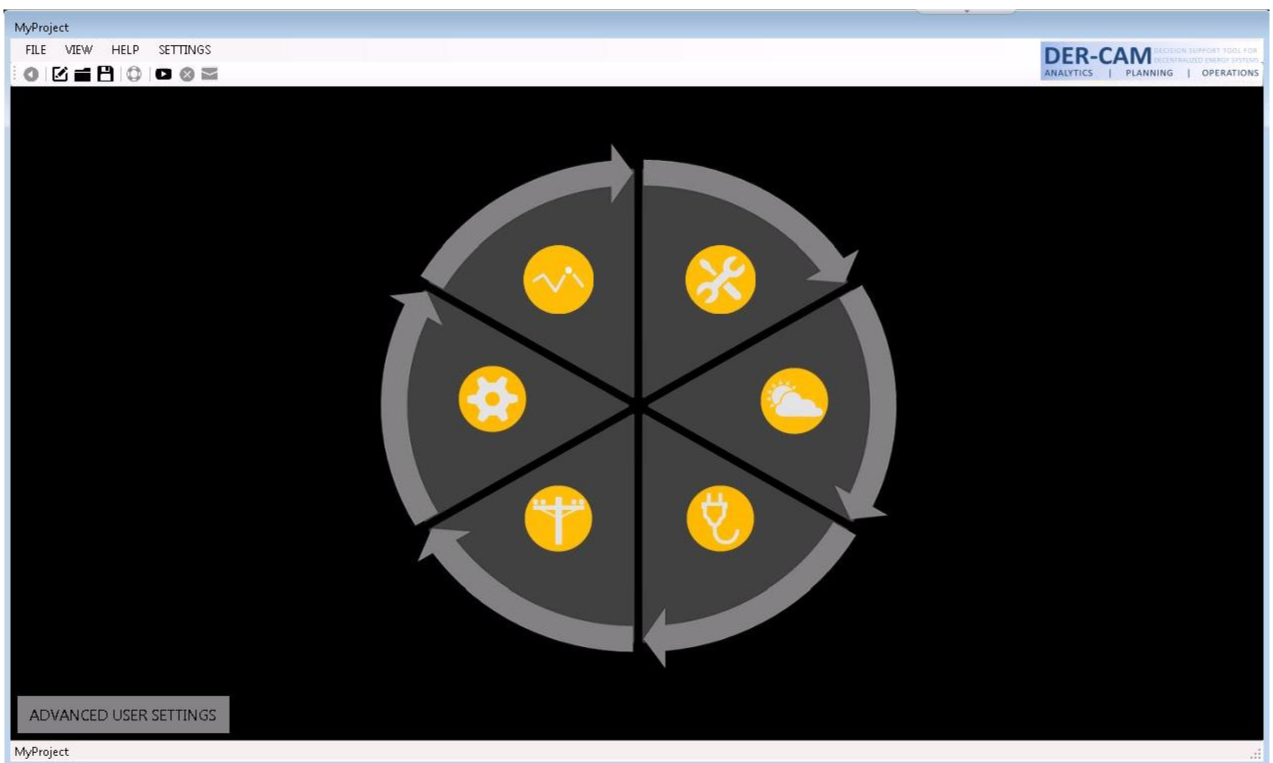


Figure 5: Main Screen, the "Pie"

III. Overview of input parameters

1. Global Settings

The first segment of the "Pie" contains the general optimization parameters that define the nature of the run that will take place. The main financial and technical parameters are included under the **Global Settings** segment, as well as the high level choice of technologies to be considered in the optimization. Three subsections are included in the **Global Settings** segment: **Options Table**, **Parameter Table** and **Number of Days**.

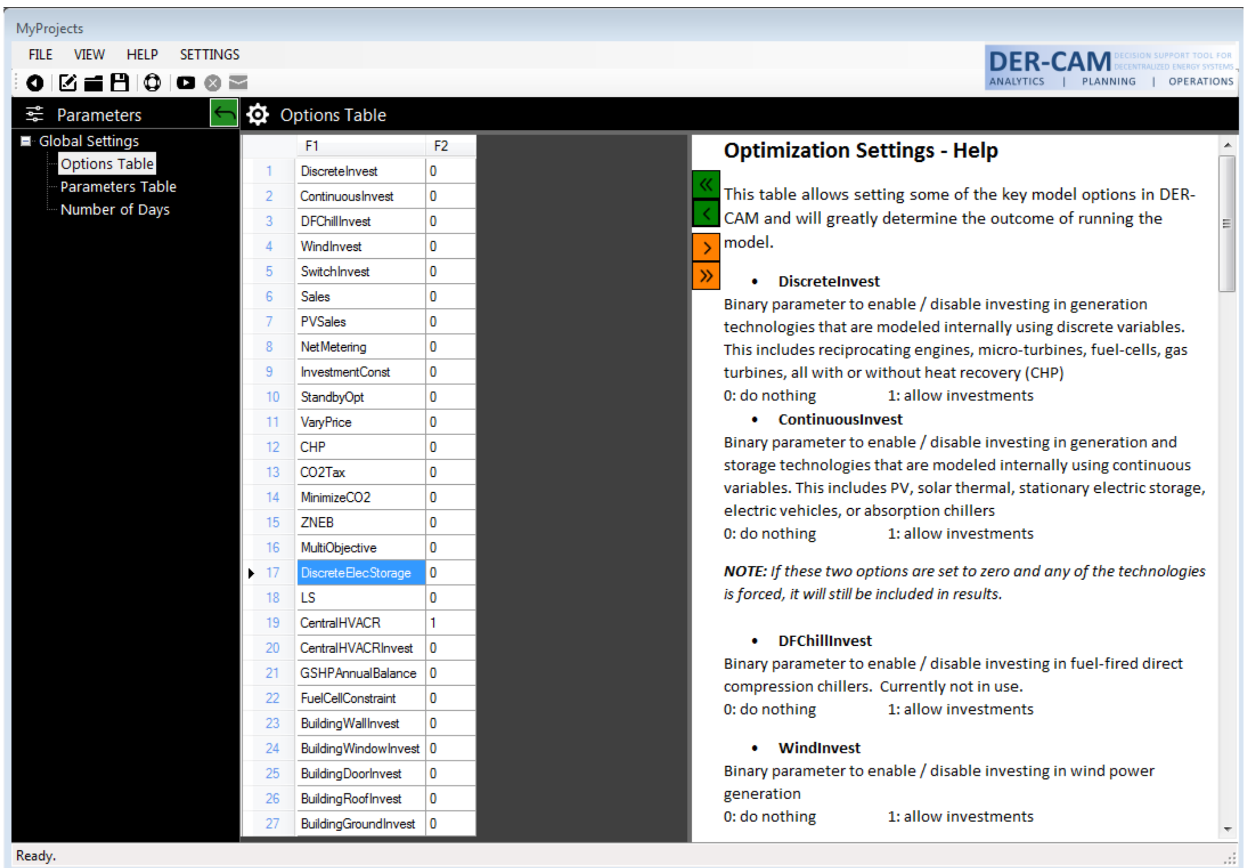


Figure 6: Global Settings, subsection Option Table

group explorer editable table help section

NOTE: Every segment of the "Pie" uses a similar layout structure: a table explorer on the left, the editable table in the middle, and specific help information for each table on the right.

The **Options Table** is a table used to define key aspects in each model. It consists of a set of binary parameters, where 0 disables the effect controlled by that parameter and 1 enables it. For instance, setting “DiscreteInvest” to 1 will enable the possibility to invest in discrete technologies, which consist of conventional distributed generation technologies modeled internally using discrete variables. This includes reciprocating engines, microturbines, fuel-cells, or gas turbines, as opposed to "continuous technologies" where capacity is modeled using continuous variables. This is an important distinction, as “Discrete technologies” can only be installed in discrete quantities of the nameplate capacity. The optimal capacity of “Continuous technologies”, however, can take any continuous non-negative number. This distinction is justified by the commercially available sizes of technologies and their economies of scale.

Likewise, if the “Sales” parameter is set to 1 DER-CAM will consider exports in the optimization process using prices found in the “PX Price” table under “Advanced User Settings”. Setting this parameter to 1 will only enable sales of conventional DG technologies, as PV sales are controlled by a specific “PVSales” parameter. Enabling “Netmetering” in addition to sales will override the “PX Price” values, and the export tariff will be set to the same tariff used for imports.

Another key element that is defined through this table is the objective function. By default, DER-CAM will minimize the economic function, but by setting “MinimizeCO2” to 1 the objective will change to CO_2 minimization, and by instead setting MultiObjective to 1 a weighted objective of both costs and CO_2 will be used.

In the **Parameter Table** several project specific global values can be set, including the key financial parameters such as the project discount rate, the maximum payback period, and the reference costs (base case cost) for investment scenarios. The reference costs represent total annual energy costs prior to new investments in distributed generation technologies and can be obtained by running DER-CAM only with the existing on-site technologies (if any). It should be noted that even in the reference case DER-CAM will optimize the dispatch of any existing DER, and therefore the reference case may already suggest relevant improvements. Enabling existing technologies will be discussed in the **Technology** section.

It is important to take into account that the base case cost is a fundamental input to DER-CAM, as it strongly relates to the maximum payback time and will largely influence which technologies are present in the optimal solution. The maximum payback constrain is active in every investment run that is performed, and forces that any new investments generate savings against the reference cost that respect a simple payback period shorter than the maximum allowed payback time. To obtain a relevant estimate of environmental performance the CO_2 emissions obtained in the base case should also be introduced in this table.

Further, it should be noted that the maximum payback constrain is still active when CO_2 minimization is selected. For this reason, it may sometimes be necessary to either increase the maximum payback period or increase the reference costs when looking for environmentally friendly solutions. This is not absolutely necessary, but failing to do so may lead to solutions that have limited potential to reduce emissions.

If "MultiObjective" is been selected as the goal, the solution found by DER-CAM will lay between the cost optimal and CO_2 optimal solutions, and the preference over one objective or the other is determined by weighting factors "MultiObjectiveWCosts" and "MultiObjectiveWCO2". However, as both these objectives are defined with different units, scaling factors must also be used.

To find the appropriate scaling factors two separate optimization runs must be performed. Namely, the scaling factor for costs, "MultiObjectiveMaxCosts", is determined by performing a CO_2 minimization run and saving the corresponding costs, and the weighting factor for CO_2, "MultiObjectiveMaxCO2", is found by performing a cost minimization run and saving the corresponding CO_2 emissions. While this is a standard approach when using weighted objectives, it should be noted that other procedures are possible and will naturally impact the results. The weighted objective function used by DER-CAM is:

$$\boldsymbol{min\ f} = \boldsymbol{MultiObjectiveWCost} * \left(\frac{\boldsymbol{TotalAnnual\ Cost}}{\boldsymbol{MultiObjectiveMax\ Cost}}\right) + \boldsymbol{MultiObjectiveWCO2} * \left(\frac{\boldsymbol{TotalAnnual\ CO2}}{\boldsymbol{MultiObjectiveMax\ CO2}}\right)$$

An alternative method to explicitly take CO_2 emissions into account in the optimization process is through the 'CO2tax' value found in the Parameter Table and enabled through the Options Table.

In summary, performing investment runs in DER-CAM requires a reference case. If used with a single objective, one base case run with no investments must be performed to obtain the 'BaseCaseCost' and 'BaseCaseCO2'. Please note that for this run you must not allow investments but existing technologies should be specified. If using the multi-objective formulation, two additional runs are needed to determine 'MultiObjectiveMaxCosts' and 'MultiObjectiveCO2'.

Number of Days shows how the set of days in a year is split between months. Possible day types include week-days, weekend-days and peak-days, as well as the emergency equivalents when considering outages. A more detailed description about emergency days is given in the 'Resiliency and Demand Management Section'. Please note that the total number of days in this table must equal the number of days in a year, i.e., when defining emergency days the equivalent number must be subtracted from the corresponding non-emergency day type.

2. Site Weather Settings

The **Site Weather Settings** segment consists of four tables: **Solar Insolation**, **Ambient Hourly Temperature**, **Other Location Data**, and **Wind Power Potential**.

Solar Insolation is used as an input to calculate the power generation by photovoltaic panels. Figure 7 shows an example of solar insolation profiles. These default profiles are location dependent and obtained by averaging historical data. It is assumed that one daily profile with hourly time steps represents the solar profile for the entire month. If the DER-CAM solar database has been used, this table will be populated automatically when the model is created.

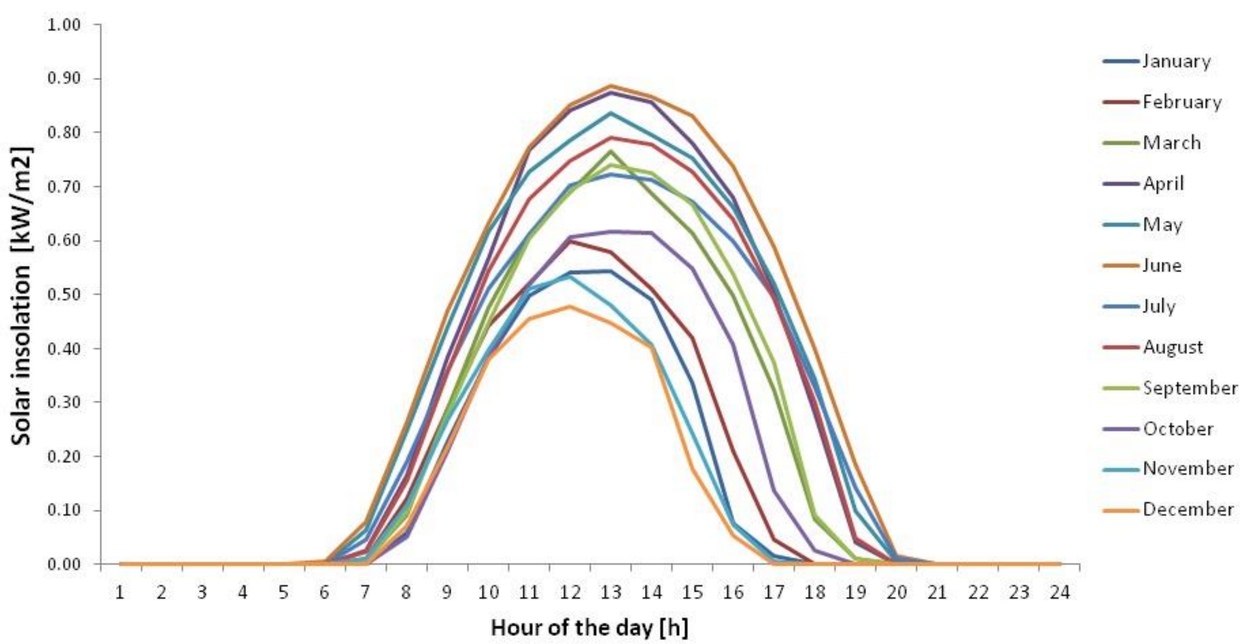


Figure 7: An example of solar insolation data

The **Ambient Hourly Temperature** defines the average hourly ambient dry-bulb temperature over each month. This information is used to estimate losses and efficiency of thermal devices such as heat storage, but it also impacts the efficiency of photovoltaic and solar thermal panels.

Other Location Data currently consists only of average annual wind speed, defined in m/s, and has an impact on the efficiency of the photovoltaic and solar thermal panels. It should be noted that this parameter does not relate with wind power.

The **Wind Power Potential** defines the maximum theoretical power output of one wind turbine, and is expressed in kWh/h/unit. Obtaining these values may be done by processing historic wind measurements and computing the theoretical power output using the turbine power curves in any desired time step and later aggregating those results to an hourly average profile per month. This approach is currently used to minimize errors that would otherwise be introduced by the time granularity used in DER-CAM.

3. Load Profiles

In the **Load Profiles** segment all load profiles can be found. Up to six types of end-use loads can be defined, including electricity-only, electric cooling, electric refrigeration, space heating, water heating, and natural-gas-only loads (eg. Cooking).

It must be noted that loads are defined as being primarily served by two energy carriers: electricity and natural gas, with electric loads including electricity-only, cooling, and refrigeration, and natural gas loads including natural-gas-only, space-heating, and water-heating.

This distinction is made so that electricity-only loads can only be served directly by electricity, whereas electric cooling and electric refrigeration loads may be offset by different energy carriers, as would be the case of heat used to drive an absorption chiller.

Similarly, natural-gas-only loads can only be served directly by natural gas, whereas space-heating and water-heating loads may eventually be served by other heat sources, such as heat recovered from CHP units, heat collected from solar thermal panels, heat collected from heat pumps, or heat collected from boilers using fuels other than natural gas.

With this in mind, both cooling and refrigeration loads are expressed by the electricity needed to drive an electric chiller of a user-defined COP, found under the Central HVACR technology definitions. Particularly, for a central chiller with a (default value) 4.5 COP, a cooling load of 1 kWh represents the electricity needed to extract 4.5 kWh of heat from the building / microgrid.

All loads must follow the standard DER-CAM format, which allows the definition of hourly load profiles for week, weekend, and peak/outlier day-types per month.

Emergency days defined for any of the standard day typed share their load definitions.

4. Utility

The **Utility** segment allows defining information regarding the utility tariffs for both electricity and fuels. Additionally, marginal CO_2 emissions may also be defined within this segment. This can be done using the tables contained in the three existing groups: **Global Settings**, **Electricity Rates**, and **Fuel Rates**.

The CO_2 information may be found in **Global Settings** and consists of both utility and fuel emission values:

- Marginal CO_2 emissions correspond to the CO_2 emissions added to the total grid emissions when supplying one additional kWh of electricity. They are defined in metric tons of CO_2/MWh (or kg of CO_2 per kWh). It is assumed that local DER will offset CO_2 emissions by this factor, while introducing their own CO_2 emissions. The net balance is used to compute total building/microgrid CO_2 emissions.
- Fuel CO_2 emissions rate contain estimated emission rates for natural gas, diesel, biodiesel and other user-defined fuels. These CO_2 emission rates are used to estimate the CO_2 production from onsite generation. They are defined as average kg of CO_2 released per kWh of energy content consumed in the combustion (LHV).

Utility charges are divided in two categories:

- Fixed charges (monthly access fee):
    - A monthly access fee charged to access the utility service. DER-CAM distinguishes between a monthly fee for electricity, natural gas, natural gas for distributed generation, natural gas for absorption chillers, and a monthly

fee for diesel supply. Setting the monthly access fee can be done in the **Global Settings** table.

- Variable charges (volumetric and power demand charges):
  - Volumetric energy costs are expressed in $/kWh and account for the final energy use. Volumetric charges are defined as Time-Of-Use rates using the three available time categories: peak, mid-peak, and off-peak hours. The definition of these categories is done in the **List of Hours** table found under **Electricity Rates**, and the **Electricity Rates** table found under **Electricity Rates > Electricity Charges** allows defining the prices set by the utility. Defining summer and winter months can be done through the **Month and Season** table found under **Global Settings**.
  - Power demand charges are expressed in $/kW and can be set on daily and/or a monthly basis. Power demand charges are dependent of the maximum demand observed within a specific control period. Control periods include the peak, mid-peak, and off-peak time categories defined in the **List of Hours** table, in addition to coincident and non-coincident control periods. The coincident hour refers to the hour when the grid observes the global system peak, and if this component is included in the tariff, the coincident hour is set by the utility on a monthly basis. The non-coincident period considers all hours, without having to coincide with any of the remaining categories. It considers all hours and not just a subset.

    The total daily/monthly demand charge is calculated by the sum of all five components. Periods where no rate applies should be set to zero.

Fuel rates may vary on a month-to-month basis, and are expressed in $/kWh of fuel consumed by combustion (LHV). Estimating the cost per kWh of final energy supply is later done in DER-CAM by dividing this value by the electric conversion efficiency of the corresponding DG equipment.

<u>Note</u>: While utility tariffs and fuel prices may vary over the years, the DER-CAM analysis done with the main stable version is considers a single representative year and tariffs are assumed to be constant.

5. Technologies

The **Technologies** segment contains all relevant techno-economical information regarding the available generation and storage technologies. It is divided into two: discrete and continuous technologies. This distinction stems from the way their capacities are modeled: The optimal capacity of discrete technologies is determined as a discrete number of units, whereas the capacity of continuous technologies is determined by a continuous variable.

Discrete technologies include gas and micro turbines, fuel cells and internal combustion engines, all of which with the possibility to operate in CHP mode by enabling heat recovery. The relevant parameters used to characterize discrete technologies can be found in the **DER Technology Info** table, where a template list of technologies is readily available for use, although at any point these values can be manually updated and saved. This table allows setting the most relevant characteristics of discrete technologies, including capital costs, operation and maintenance costs, electric conversion efficiency (LHV), heat-to-power ratio, technology lifetime, among others.

It should be noted that while a constant electric efficiency is typically used, it is possible to enable variable part-load efficiency in internal combustion engines, micro-turbines, and fuel cells by setting "efficiency_var" to 1, although this has a very significant impact on computation time.

Apart from the techno-economic characterization of discrete technologies done through this table, an additional set of constrains is also required. These constrains can be found in the **Generator Constraints** table, and include both the minimum part-load operation, "MinLoad", and the maximum number of hours per year each technology may operate, "MaxAnnualHours". Properly defining these parameters allows minimizing the errors introduced by assuming constant electric conversion efficiency, as well as considering scheduled maintenance time.

Furthermore the "MaxAnnualHours" parameter can be used to disable a specific technology by setting this value to 0.

Finally, the **Generator Constrains** table can be used to model existing equipment and / or force equipment in the solution. The following logic is used for this purpose:

ForcedNumber – sets the minimum number of units present in the solution

ForcedInvestment – if enabled sets the *ForcedNumber* to be the <u>exact number</u> of units present in the solution

Existing – if enabled sets the *ForcedNumber* of units as pre-existing

Example 1

Force exactly two new units to be present in the solution:
ForcedInvestment = 1; ForcedNumber = 2; Existing = 0.

Example 2

Force at least three new units to be present in the solution:
ForcedInvestment = 0; ForcedNumber = 3; Existing = 0.

Example 3

Force at least two existing unit to be present in the solution:
ForcedInvestment = 0; ForcedNumber = 2; Existing = 1.

Example 4

Allow any number of units to be present in the solution, where no unit already exists:
ForcedInvestment = 0; ForcedNumber = 0; Existing = 0.

Please note that this table interacts with the *DiscreteInvest* parameter in the **Options Table** found in the **Global Settings** segment. In particular, setting this parameter to zero globally disables all new investments in discrete technologies, and exactly the *ForcedNumber* will be present in the solution.

Continuous technologies include technologies where the existing market sizes and the economies of scale allow modeling the optimal capacity using a continuous variable and defining the investment cost by a fixed and variable cost. Fixed costs are incurred regardless of the installed capacity, and can describe installation costs. Variable costs are capacity dependent, and are described per unit of capacity.

Similarly to Discrete Technologies, a template list of parameters is provided by default with DER-CAM, but these values can manually be updated at any time.

Including existing equipment in results follows a procedure similar to what is done with Discrete Technologies, although the *ForcedNumber* parameter is now replaced by *ForcedCapacity*. Thus, the following logic is used for this purpose:

ForcedCapacity – sets the minimum capacity present in the solution

ForcedInvestment – if enabled sets the *ForcedCapacity* to be the exact capacity present in the solution

Existing – if enabled sets the *ForcedCapacity* as pre-existing

Example 1

Force exactly 100kW of new capacity to be present in the solution:
ForcedInvestment = 1; ForcedCapacity = 100; Existing = 0.

Example 2

Force at least 200kW of new capacity to be present in the solution:
ForcedInvestment = 0; ForcedCapacity = 200; Existing = 0.

Example 3

Force at least 150 kW of existing capacity to be present in the solution:
ForcedInvestment = 0; ForcedCapacity = 150; Existing = 1.

Example 4

Allow any capacity to be present in the solution, where no capacity already exists:
ForcedInvestment = 0; ForcedCapacity = 0; Existing = 0.
Within the continuous technologies, all storage technologies have their own specific technical parameters. For instance, **Storage specific Parameters** groups specific information for electric storage, heat storage and electric vehicle such as the charging and discharging efficiency, the storage decay (portion of stored energy lost per hour due to self-discharge) and the maximum and minimum state of charge and charge and discharge rates. Notice that for Heat Storage these parameters are available both for high and low temperatures as DER-CAM models heat storage tanks with two temperature strata.

6. Energy management and resiliency

The Energy management and resiliency segment allows defining measures that do not directly represent any form of generation and / or storage, but rather influence the optimal dispatch of the available DER, and therefore may impact investment decisions. These energy management measures include Load Shifting (LS), Demand Response (DR), and Direct Controllable Loads (DCL). During outage events, an additional type of energy management may also occur: Load Curtailment.

- **Load Shifting**: the main difference between load shifting and the other two demand management options is the fact that when load shifting is applied the total energy demand remains unchanged. Instead, a percentage of the total load of each day-type is seen as movable in time, and this percentage is user-defined. Currently, no cost is associated to this measure, which translates in high potential to shift demand from periods of high time-of-use rates to those where costs are lower. As a result, load shifting tends to flatten demand profiles, which not only leads to lower energy purchase costs, but also minimizes power demand charges. In addition to specifying how much total load can be shifted, a maximum decrease and increase per hour may also be defined. These values can be set independently for different day-types.

- **Demand Response**: demand response events in DER-CAM are modeled as decisions to curtail the end-use load due to price signals from the utility, if the microgrid is connected with the grid, or due to local generation costs, if the microgrid is in islanded mode. This decisions is made by assigning a cost to curtailing loads, which can be categorized in up to three different priority levels - high, mid, and low. While it is not necessary to define all three load priorities, the sum of all fractions must be less than or equal to one, as this would imply allowing all load to be curtailed. Conversely, if the sum of all fractions is lower than one, the remaining load cannot be curtailed. In practice this can be seen as defining a fourth load type, thus effectively having non-curtailable, high, mid, and low priority levels. For each curtailable load type, two parameters can be set in addition to the percentage of hourly load. These are the curtailment cost, in $/kW, reflecting the costs incurred by the building or microgrid in the event of load curtailment, and the annual maximum number of hours that this specific type of curtailment may occur.

- **Direct Controllable Loads**: This energy demand management event may be regarded as a special case of demand response. Direct controllable loads are defined as 24h loads where values can be specified hourly, whereas general demand response events are defined as a percentage of total load per priority level. Each direct controllable load requires the following data: 24h load profile (DCL Value), curtailment cost, maximum number of curtailment hours, specification of day-types where the directly controllable load is present (DCL and Days), and curtailment mode, which defines whether the load may be curtailed for less than its entirety or not (Full-LengthDCL). Table 1 gives a numerical example of different settings of the parameters and their implication.

Full-LengthDCL	Number of non-zero entries in DCL Value table	MaxHours	Number of days during which curtailment is possible
1	>5	5	0
0	>5	5	≤5
1	5,4 or 3	5	1
1	2	5	2
1	1	5	5

The resiliency subsection allows modeling medium to long term grid outages, allowing a better understanding of how resilient a microgrid is to events such as natural disasters, and which investments would be necessary to cope with grid outages. Two tables are used for this purpose: the **Number of Days** table, also found in the **Global Settings** segment, and the **Electric Utility Availability** table.

- **Number of Days**: Grid outages can only occur during emergency days. For this reason, modeling outages in DER-CAM requires specifying the corresponding number of days using this table. Namely, to model a grid outage during one single weekday in March, one 'Emergency-week' in March needs to be defined while the number of standard weekdays in March needs to be decreased by the same amount.

- **Electric Utility Availability**: This table allows defining the hourly availability of the utility grid. By default, the grid is available during normal day-types and can only be set to zero during emergency days. If for example we consider one emergency weekday in March where the grid is unavailable from 11 am to 4 pm, the corresponding values must be set to zero for this 5 hour outage to be considered. If the grid availability is set to 1 for every hour the declaration of the emergency day has no impact on results as the grid is still set to be available at all times during emergency days. Likewise, setting the electric utility availability to zero is not taken into account if there is no corresponding emergency day declared for that particular day-type. The availability of the electric utility is specified on an hourly basis for each month and day-type. Sub-hourly outages can be defined, although they will only represent a drop in the hourly energy consumption, due to the fact that hourly time-steps are used.

Load Curtailment is a specific case of energy management when the utility is unavailable and the microgrid is in forced islanding. If the energy demand is greater than the local generation capacity and available storage, a percentage of the load will necessarily be curtailed. This is done at a cost to the microgrid which is the cost associated to the loss of service. Estimating this value represents a complex task that often requires visiting the site at hand and understanding all costs that may occur due to prolonged outages.

Please note that if an outage is forced and curtailments are disabled (MaxCurtailment=0 or MaxHours=0) it may be necessary to enable investments in order to meet the load, as otherwise the model may become infeasible. Furthermore, it should be noted that when doing investment analysis the reference cost must reflect the outage costs in order to properly value the DER investments needed to offset the outage costs.

7. Advanced User Settings

The **Advanced User Settings** segment contains specific DER-CAM features consisting of two blocks: "**Building Retrofit Settings**" and "**Financial Incentives**". In order to take these features into account they must be enabled in the **Options Table** under **Global Settings**.

Building retrofit settings: In addition to active generation, storage technologies, and energy management measures, it is also possible to consider building retrofits in DER-CAM as a way to minimize total energy costs and / or CO_2 emissions. Investing in passive measures will impact the energy loads, which may be a more cost-effective solution to the problem than investing in active technologies. In order to do this, DER-CAM considers changes in the overall heat transfer coefficient or U-value of different building components and estimates heat losses to gauge the impact of passive building improvements in the original energy loads input by the user. It should be noted that this is a simplified model that does not consider all forms of heat transfer and will therefore only provide guidance on whether or not building retrofits should be considered.

Financial incentives: This section consists of two parts. The standard form of financial incentive available in DER-CAM is the ability to export power back to the utility. This may be done at one of two tariff options: By net-metering, if enabled in the Global Options segment, or by setting the power exchange prices in the **PX** table.
The second part of this section is specific to the California Self-Generation Incentive Program. It contains some of the most relevant constrains that have been defined within this program, including maximum on-site capacity, efficiency constrains, feed-in tariffs, and investment subsidies.

IV. Case Study

In this section we will create a project and go through all the steps of the DER-CAM workflow to provide the user with a complete and detailed example.

1. Starting the project

To start a new DER-CAM project please login to the site using your credentials, and when presented with the main interface select "New Project" or go to Menu File > New Project (please refer to the section *Getting started with DER-CAM* for more details).

When creating a new project you will be able to specify a unique name for it, as well as the version of DER-CAM you would like to use. Additionally, you can choose to use the existing load and solar databases. In this case study, we have selected "CaseStudy" as the project name, and selected DER-CAM Version 4.4.1.3, along with the option to use the DER-CAM databases.

The selected building is located in San Francisco, California, and consists of a large office building with Pre 1980 construction. The loads have been scaled to 1GWh, and Oakland solar data has been used (Figure 8).

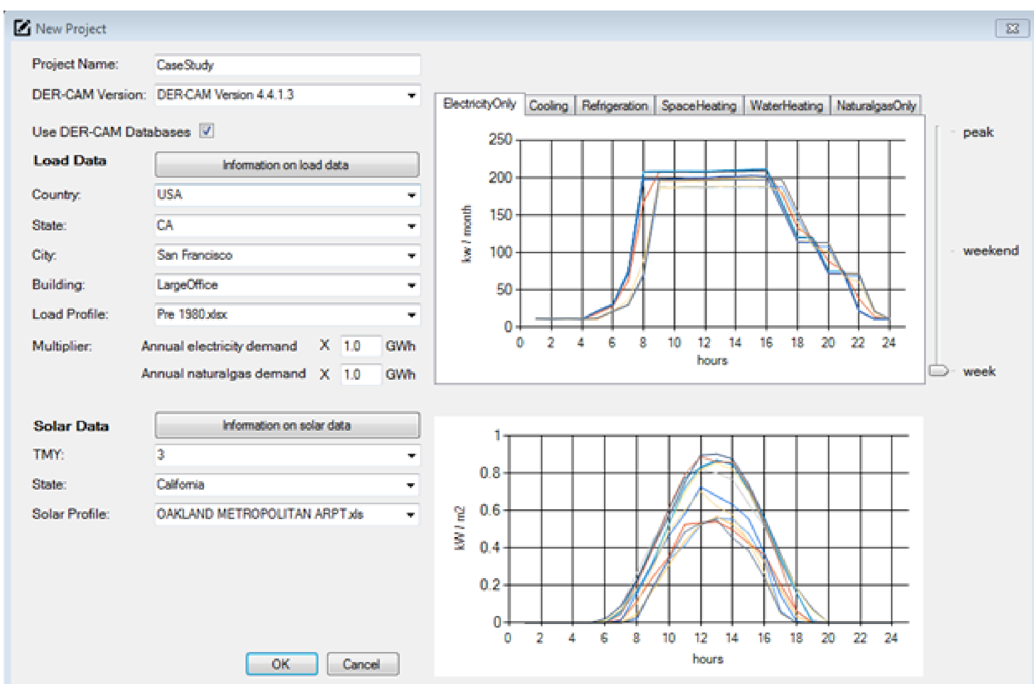


Figure 8: Creation of a new project

2. Reference Case

Before using DER-CAM to find optimal DER investment options we will need to run a base case to establish reference costs and CO_2 emissions. The first table we look at is the **Options Table** under **Global Settings**.

To do this we start by going to the **Global Settings** segment and in the **General Options** table disable all investment options by setting the first 5 parameters to zero (Figure 9). Only the parameter CentralHVACR is set to 1, because it is assumed that central HVACR is available in order to meet cooling and heating loads. All the other options are set to 0.

The purpose of this run is to properly fill the BaseCaseCost and BaseCaseCO2 found in the **ParameterTable** within the **Global Settings** segment (Figure 9). These values are set to arbitrary large numbers by default, but need to be updated before conducting meaningful investment analysis.

1	IntRate	0.05
2	Standby	0
3	Contrct	0
4	tumvar	0
5	CO2Tax	0.272727
6	macroeff	0.34
7	cooleff	0
8	BaseCaseCost	347630000
9	BaseCaseCO2	50000000
10	MaxPaybackPeriod	10
11	FractionBaseLoad	0.5
12	FractionPeakLoad	0.1
13	ReliabilityDER	0.9
14	MaxSpaceAvailablePVSolar	1620000
15	PeakPVEfficiency	0.1529
16	MultiObjectiveMaxCosts	2900000
17	MultiObjectiveMaxCO2	4400000
18	MultiObjectiveWCosts	0.6
19	MultiObjectiveWCO2	0.4
20	ZNEBsolarAreaMultiplier	200
21	ZNEBCostsMultiplier	2
22	BldgShellLifetime	20
23	MinAnnDERGen	0
24	MinAnnRENGen	0
25	MaxExportkW	10000

1	DiscreteInvest	0
2	ContinuousInvest	0
3	DFChillInvest	0
4	WindInvest	0
5	SwitchInvest	0
6	Sales	0
7	PVSales	0
8	NetMetering	0
9	InvestmentConst	0
10	StandbyOpt	0
11	VaryPrice	0
12	CHP	0
13	CO2Tax	0
14	MinimizeCO2	0
15	ZNEB	0
16	MultiObjective	0
17	DiscreteElecStorage	0
18	LS	0
19	CentralHVACR	1
20	CentralHVACRInvest	0
21	GSHPAnnualBalance	0
22	FuelCellConstraint	0
23	BuildingWallInvest	0
24	BuildingWindowInvest	0
25	BuildingDoorInvest	0
26	BuildingRoofInvest	0
27	BuildingGroundInvest	0

Figure 9: Option and Parameter Table

Finally, the **Number of Days** table allows setting the number of week-days, weekend-days and peak-days in each month.

	F1	peak	week	weekend	emergency-week	emergency-peak	emergency-weekend
1	January	3	20	8	0	0	0
2	February	3	17	8	0	0	0
3	March	3	18	10	0	0	0
4	April	3	19	8	0	0	0
5	May	3	20	8	0	0	0
6	June	3	17	10	0	0	0
7	July	3	20	8	0	0	0
8	August	3	18	9	0	0	0
9	September	3	18	9	0	0	0
10	October	3	20	8	0	0	0
11	November	3	18	9	0	0	0
12	December	3	19	9	0	0	0

Figure 10: Number of days Table

Next, we go to the **Site Weather settings** section. In this case study we have selected solar insolation profiles from the database and use the default settings for ambient temperature, other locational data and wind power potential. However, these values can be updated at any moment if necessary.

Solar Insolation

	month	1	2	3	4	5	6	7	8	9
1	january	0	0	0	0	0	0	0	0.0197810472846069	0.186537009393074
2	february	0	0	0	0	0	0	0.000285437873431821	0.0443155694058229	0.175189393219209
3	march	0	0	0	0	0	0	0.0168181139768991	0.115143795965081	0.244664818683985
4	april	0	0	0	0	0	0.00107576229174917	0.0636750765775013	0.22718667427667	0.417246039136739
5	may	0	0	0	0	0	0.0152683556718232	0.0921498879283911	0.265998324808381	0.440813951566675
6	june	0	0	0	0	0	0.0209894051060387	0.0883719042348125	0.229546831973217	0.397287180617402
7	july	0	0	0	0	0	0.0109772155615321	0.0707733824477676	0.175933757157933	0.311636178431393
8	august	0	0	0	0	0	0.00131000734701486	0.0533516419474728	0.171441726075499	0.325904496016436
9	september	0	0	0	0	0	0	0.0434482830423937	0.206410697681664	0.395792891212922
10	october	0	0	0	0	0	0	0.0116513511143017	0.156689911382883	0.31457871579954
11	november	0	0	0	0	0	0	0	0.102908170706116	0.294223205201234
12	december	0	0	0	0	0	0	0	0.025586574230324	0.191531765457728

	month	10	11	12	13	14	15
1	january	0.338479034177729	0.413951758107726	0.522642777473655	0.560456485871342	0.553642133158955	0.476424164
2	february	0.308056920071197	0.43675427608738	0.525516098745598	0.567372271552981	0.525226789187761	0.439280817
3	march	0.35277938735671	0.526505842602104	0.535066605313602	0.54061096500894	0.497338691827377	0.423729884
4	april	0.607488598333719	0.776418456994637	0.828620213505062	0.865590655106638	0.854350705853275	0.703965579
5	may	0.578330070318346	0.716045929793789	0.81962034151727	0.799793128201064	0.766427685759508	0.634468181
6	june	0.569383720131487	0.750588775897209	0.896367549806794	0.902536376981685	0.87610654357502	0.740097815
7	july	0.523383150030296	0.698167563486432	0.817602761710936	0.85427848248486	0.819150515138665	0.700638388
8	august	0.527494031257777	0.724918138100952	0.833877682335533	0.870633786853369	0.844169992595016	0.715783719
9	september	0.613652100927677	0.793461572035835	0.888708566359397	0.860289407566147	0.85829416884362	0.724942731
10	october	0.465440480829001	0.582003312208589	0.725921528072055	0.676774994792261	0.631992993752723	0.555373715
11	november	0.485189890924014	0.603315721553552	0.701422101963283	0.622212282137103	0.576440059949805	0.431711470
12	december	0.341650562529462	0.486139496749366	0.533224043529774	0.551798681561941	0.453198606442366	0.385872968

Ambient Hourly Temperature

	F1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	January	8.1	7.9	7.8	7.7	7.8	7.9	8	8.9	9.7	10.6	11.5	12.4	13.3	13.4	13.6	13.8	12.8	11.9	10.9	10.4	9.9	9.3	8.9	8.5
2	February	9.7	9.5	9.3	9.1	8.8	8.6	8.2	9.5	10.7	12	13.2	14.4	15.5	15.6	15.7	15.8	14.9	13.9	13	12.3	11.7	11.1	10.5	10.1
3	March	11.1	10.6	10.1	9.6	9.3	9	8.7	9.9	11.1	12.3	13.4	14.5	15.6	15.9	16.1	16.4	15.6	14.8	14	13.6	13.1	12.6	12.1	11.6
4	April	10.3	9.8	9.4	9	9.4	9.7	10.1	11.5	13	14.5	15.6	16.8	18	18.1	18.2	18.4	17	15.5	14.1	13.5	12.9	12.2	11.5	10.8
5	May	11.2	11.1	10.8	10.4	10.9	11.3	11.7	13.2	14.6	16.1	17.5	18.9	20.4	20.2	20	19.8	18.2	16.6	15	14	13.2	12.2	11.7	11.5
6	June	13	12.9	12.7	12.3	12.9	13.6	14.2	15.5	16.7	18	19.4	20.7	22	21.6	21.1	20.7	19.3	17.8	16.4	15.5	14.7	13.8	13.3	13.1
7	July	13.4	13.3	13.1	13	13.4	13.7	14.1	15.5	16.9	18.3	19.8	21.3	22.8	22.4	22.1	21.8	20.2	18.6	17.1	16.3	15.5	14.7	14	13.7
8	August	14	13.8	13.6	13.4	13.5	13.7	13.9	15.2	16.5	17.9	19.6	21.4	23.1	22.6	22.1	21.6	20.1	18.5	17.1	16.3	15.7	14.9	14.4	14.1
9	September	14.8	14.5	14.1	13.7	13.5	13.7	14.7	16.2	17.7	19	20.6	22.2	23.4	23.6	23.2	22.4	21.3	19.5	18.2	17.2	16.6	16.1	15.6	15.2
10	October	13.4	12.9	12.4	11.9	12.1	12.3	12.5	14.2	15.8	17.4	18.6	19.9	21.1	21.2	21.2	21.3	19.9	18.6	17.2	16.6	16	15.3	14.6	13.9
11	November	10.8	10.2	9.6	9.2	9.3	9.3	9.9	11.5	13.4	14.4	15.3	16.6	17.1	17.4	17.3	16.3	15	14.1	13.3	12.7	11.9	11.7	11.5	11.2
12	December	8.2	7.9	7.4	6.9	6.9	7	7	8.1	9.3	10.4	11.5	12.6	13.6	13.8	13.9	14.1	13	12	11	10.3	9.7	9.1	8.6	8.3

Other Location Data

	F1	F2
1	WindSpeed	5

Wind Power Potential

	F1	F2	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	January	week	5.84	6.3	7.23	8.2	10.22	7.88	5.29	5.72	7	6.65	7.43	9.03	9.24	8.28	7.87	6.65	4.62	4.52	3.76	4.47	4.72	4.92	5.23	7.65
2	February	week	9.86	10.24	10.93	7.43	6.37	5.17	6.02	6.7	4.96	5.46	7.01	7.97	7.91	9	8.23	7.82	7.32	6.88	6.51	5.81	5.23	6.52	8.35	10.17
3	March	week	19.72	20.33	18.97	17.22	14.31	12.09	12.16	13.64	14.99	14.28	13.77	14.46	13.77	13.07	11.83	11.59	10.25	9.51	10.14	10.27	13.27	14.5	17.48	20.01
4	April	week	14.27	12.49	9.87	10.21	8.93	9.55	8.87	7.05	7.29	7.62	7.11	6.55	5.99	5.38	7.82	6.82	4.8	5.88	7.32	8.38	9.41	13.05	15.14	18.01
5	May	week	12.3	12.73	10.8	8.21	7.14	7.38	7.12	5.96	4.69	3.5	3.02	2.5	2.07	2.5	3.05	2.81	2.92	4.27	4.67	5.21	5.7	6.91	9	12.45
6	June	week	11.73	10.83	9.51	9.09	9.09	9.14	8.97	7.51	7.72	7.33	5.04	4.21	3.43	2.97	1.92	1.29	1.3	1.48	2.23	2.33	2.86	4.13	6.61	13.1
7	July	week	13.19	11.47	11.73	13.47	13.05	11.77	11.2	9.49	7.74	6.2	4.72	2.89	2.19	1.62	1.33	0.63	1.23	2.15	3.01	3.82	4.55	5.51	7.62	11.68
8	August	week	8.75	7.54	6.6	6.69	5.63	4.32	4.35	3.69	3.03	2.1	1.98	1.66	1.54	1.41	1.06	0.78	0.67	0.69	0.92	1.34	1.82	2.31	4.02	6.77
9	September	week	6.97	6.3	6.58	5.03	4.17	4.09	4.03	3.02	2.18	1.33	0.93	0.48	1.02	1.31	1.63	1.85	1.96	3.36	4.13	4.73	4.68	4.15	4.95	7.76
10	October	week	9.04	6.87	7.33	5.97	5.23	5.21	3.76	2.89	2	2.01	1.95	2.05	2.29	1.97	1.85	1.95	1.83	1.23	1.73	2.3	2.64	2.35	3.32	6.01
11	November	week	7.35	8.04	6.73	7.07	5.88	4.3	4.3	2.99	3.2	2.63	1.97	1.98	1.03	0.94	0.82	0.99	1.35	2.32	2.82	3.45	3.47	3.47	4.38	7.21
12	December	week	7.26	6.54	5.73	7.69	6.82	7.26	5.96	6.53	6.29	6.16	5.21	5.33	5.46	4.69	5.11	6.51	6.91	7.96	7.65	7.95	8.96	9.37	8.94	9.13
13	January	peak	5.84	6.3	7.23	8.2	10.22	7.88	5.29	5.72	7	6.65	7.43	9.03	9.24	8.28	7.87	6.65	4.62	4.52	3.76	4.47	4.72	4.92	5.23	7.65
14	February	peak	9.86	10.24	10.93	7.43	6.37	5.17	6.02	6.7	4.96	5.46	7.01	7.97	7.91	9	8.23	7.82	7.32	6.88	6.51	5.81	5.23	6.52	8.35	10.17
15	March	peak	19.72	20.33	18.97	17.22	14.31	12.09	12.16	13.64	14.99	14.28	13.77	14.46	13.77	13.07	11.83	11.59	10.25	9.51	10.14	10.27	13.27	14.5	17.48	20.01
16	April	peak	14.27	12.49	9.87	10.21	8.93	9.55	8.87	7.05	7.29	7.62	7.11	6.55	5.99	5.38	7.82	6.82	4.8	5.88	7.32	8.38	9.41	13.05	15.14	18.01
17	May	peak	12.3	12.73	10.8	8.21	7.14	7.38	7.12	5.96	4.69	3.5	3.02	2.5	2.07	2.5	3.05	2.81	2.92	4.27	4.67	5.21	5.7	6.91	9	12.45
18	June	peak	11.73	10.83	9.51	9.09	9.09	9.14	8.97	7.51	7.72	7.33	5.04	4.21	3.43	2.97	1.92	1.29	1.3	1.48	2.23	2.33	2.86	4.13	6.61	13.1
19	July	peak	13.19	11.47	11.73	13.47	13.05	11.77	11.2	9.49	7.74	6.2	4.72	2.89	2.19	1.62	1.33	0.63	1.23	2.15	3.01	3.82	4.55	5.51	7.62	11.68
20	August	peak	8.75	7.54	6.6	6.69	5.63	4.32	4.35	3.69	3.03	2.1	1.98	1.66	1.54	1.41	1.06	0.78	0.67	0.69	0.92	1.34	1.82	2.31	4.02	6.77
21	September	peak	6.97	6.3	6.58	5.03	4.17	4.09	4.03	3.02	2.18	1.33	0.93	0.48	1.02	1.31	1.63	1.85	1.96	3.36	4.13	4.73	4.68	4.15	4.95	7.76
22	October	peak	9.04	6.87	7.33	5.97	5.23	5.21	3.76	2.89	2	2.01	1.95	2.05	2.29	1.97	1.85	1.95	1.83	1.23	1.73	2.3	2.64	2.35	3.32	6.01
23	November	peak	7.35	8.04	6.73	7.07	5.88	4.3	4.3	2.99	3.2	2.63	1.97	1.98	1.03	0.94	0.82	0.99	1.35	2.32	2.82	3.45	3.47	3.47	4.38	7.21
24	December	peak	7.26	6.54	5.73	7.69	6.82	7.26	5.96	6.53	6.29	6.16	5.21	5.33	5.46	4.69	5.11	6.51	6.91	7.96	7.65	7.95	8.96	9.37	8.94	9.13
25	January	weekend	8.42	4.64	5.04	4.57	3.23	3.97	3.84	4.09	2.45	5.09	5.82	6.68	6.3	6.72	7.81	8.24	7.93	8.01	8.24	9.19	11.37	13.59	13.01	7.98
26	February	weekend	4.04	3.92	5.45	5.38	2.87	2.56	3.42	1.45	3.39	5.15	6.55	5.85	4.39	6.79	8.04	9.42	10.78	6.53	3.48	0.9	1.21	2.3	2.84	6.33
27	March	weekend	22.61	17.72	15.75	21.65	20.08	18.29	19.12	14.4	10.73	13.12	14.27	13.04	10.73	9.84	9.05	11.32	11.83	11.41	11.29	12.03	13.12	14.38	15.27	17.21
28	April	weekend	22.75	23.49	22.22	22.22	22.6	24.36	20.99	18.44	15.81	12.56	13.7	10.04	8.97	9.25	8.13	6.44	6.04	7.07	8.08	9.43	10.29	14.25	14.4	17.38
29	May	weekend	20.2	16.78	13.87	14.5	16.28	13.71	14.06	10.57	5.8	5.37	4.2	2.94	3.57	3.04	2.03	2.09	4.53	6.44	5.01	4.6	6.31	8.57	10.11	13.07
30	June	weekend	11.17	10.76	9.06	9.02	8.67	7.12	7.2	6.55	5.49	4.15	2.76	2.69	1.88	0.76	0.48	0.12	0.36	0.52	0.68	1.38	2.36	4	6.43	9.07
31	July	weekend	11.23	8.82	7.91	7.88	8.69	7.32	6.35	5.85	6.11	5.04	5.33	4.97	4.73	4.09	3.57	1.22	0.91	1.23	1.67	1.84	2.95	4.43	7.09	11.41
32	August	weekend	11.73	9.69	7.18	6.49	5.2	4.57	3.69	3.42	2.98	3.13	1.94	0.79	0.43	0.3	0.05	0	0.33	1.01	1.07	1.47	1.52	2.01	3.73	10.92
33	September	weekend	10.75	7.9	8.22	6.52	5.47	5.91	8.9	8.23	6.33	4.82	2.46	1.06	1.11	0.61	0.35	0.24	0.08	0.34	0.58	0.51	0.67	0.76	1.3	3.71
34	October	weekend	6.82	5.15	3.49	2.68	3.14	3.07	3.69	2.65	1.81	1.48	2.26	2.64	2.07	2.34	2.42	3.53	2.67	2.22	4.12	5.53	6.26	6.46	8.2	12.15
35	November	weekend	1.18	2.39	2.28	3.54	3.92	3.1	0.54	0.55	0.63	0.86	1.93	1.28	0.76	1.59	1.26	0.49	0.19	0.05	0	0.07	0.92	1.16	0.59	0.79
36	December	weekend	9.2	9.25	5.42	2.39	7.63	10.98	9.4	4.58	5.86	5.32	4.7	4.48	5.2	6.21	5.5	9.39	9.18	7.85	3.32	4.52	5.18	8.09	7.06	7.96

Figure 11: "Site Weather Settings" Tables

Following the **Site Weather Settings** we find the **Load Profiles** (Figure 12). Once again, we have opted to use the existing DER-CAM database to pre-fill this information, but it is still available for any necessary edits.

Load

	type	month	daytype	1	2	3	4	5	6	7
1	electricity-only	January	week	12.4036679938178	11.1746929276455	12.4978910983523	11.2670315700894	12.8525982229484	21.191390489905	29.605035778896
2	electricity-only	February	week	11.0849100123972	11.0989511024847	11.0989511024847	11.1452866997735	11.0989511024847	21.4867935018134	30.085323940149
3	electricity-only	March	week	11.1131677061983	11.0743791948316	11.1400212909907	11.1077969892399	18.8682168742241	28.4688115479151	62.070031806854
4	electricity-only	April	week	11.0989511024847	11.0568278322223	11.0989511024847	11.0778894673535	22.1347172995758	31.2347966325537	75.285897394030
5	electricity-only	May	week	11.0147045619598	11.0147045619598	11.0147045619598	11.0326069518213	21.4965762856831	30.2498153856795	72.072414910478
6	electricity-only	June	week	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239195	31.2832842959843	75.285897394030
7	electricity-only	July	week	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	21.4174810926996	30.1705080531235	72.079019769267
8	electricity-only	August	week	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239195	31.316850119882	75.285897394030
9	electricity-only	September	week	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	21.4174810926996	30.1966298438728	71.715275570026
10	electricity-only	October	week	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	21.4496878311848	30.2279862274889	71.903203034447
11	electricity-only	November	week	11.0900830455874	11.0147045619598	11.1340538277035	11.0775199649828	12.9046254074191	22.4318953643993	36.056116281720
12	electricity-only	December	week	11.9972480538587	11.0942707391222	12.0477524245322	11.1638911441394	12.2005716047839	21.6163965356057	30.599958556957
13	electricity-only	January	peak	11.0147045619598	11.4324269920627	11.0147045619598	11.4921016249346	11.0147045619598	22.6659385412193	31.227079146191
14	electricity-only	February	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.248660469512
15	electricity-only	March	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	14.8454051036046	25.0952991313434	45.940598060769
16	electricity-only	April	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.3252028098511	75.285897394030
17	electricity-only	May	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.3513433730907	75.285897394030
18	electricity-only	June	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.4033147692567	75.285906174560
19	electricity-only	July	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.3716092154025	75.337144069557
20	electricity-only	August	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.3481438884008	75.285897394030
21	electricity-only	September	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.4848122337692	75.285897394030
22	electricity-only	October	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.3367459300669	75.285897394030
23	electricity-only	November	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.0294091239196	31.238351542812
24	electricity-only	December	peak	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.1487583896633	31.227079146191
25	electricity-only	January	weekend	12.0024634058938	11.118140592271	12.0024634058938	11.3528608149003	12.0024634058938	11.4125354477721	20.985740998885
26	electricity-only	February	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.1191351694855	11.0147045619598	11.2832404098831	21.123910621420
27	electricity-only	March	weekend	11.0147045619598	11.0743791948316	11.0147045619598	11.1489724859214	11.1042165112676	16.306496739505	21.210762273249
28	electricity-only	April	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0505093416829	11.086314121406	21.2765737913705	21.192501413521
29	electricity-only	May	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0594605366137	11.0147045619598	21.2275884128899	21.120891854075
30	electricity-only	June	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	21.1602859037892	21.120891854075
31	electricity-only	July	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	21.1768593393059	21.733990724407
32	electricity-only	August	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	21.166270103771	21.120891854075
33	electricity-only	September	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	22.3391731837009	22.243801553199
34	electricity-only	October	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	20.0394029442149	19.997982154951
35	electricity-only	November	weekend	11.0147045619598	11.0147045619598	11.0147045619598	11.0147045619598	11.0594605366137	13.5412513849887	21.255159778037

Figure 12: Loads Table

The **Utility** segment is then used to define the relevant utility tariffs. In this case, we are using PG&E tariff E-19 Secondary, for medium/large buildings (Figure 13). This tariff consists of both power demand charges and time-of-use energy rates, defined over three control periods: peak, shoulder, off-peak, and rates vary on a monthly basis. To model these tariffs, tables reported in Figure 15 are used. Please note that DER-CAM uses hourly time periods whereas PG&E uses half-hourly ones (for instance, Partial-Peak hours in Summer are from 8:30 am to 12 noon and from 6 pm to 8:30 pm). In this case, we are using conservative values to take this into account, i.e. the remaining half-hour is modeled with the most expensive of the two rates. Thus, in our case, Partial-Peak (mid-peak) hours in Summer are from 8 am to 12 noon and from 6 pm to 9 pm (Figure 15).

Rate Schedule	Customer Charge	Season	Time-of-Use Period	Demand Charge (per kW)			Time-of-Use Period	Total Energy Charge (per kWh)		
				Secondary	Primary	Transmission		Secondary	Primary	Transmission
A-1	Single Phase Service per meter/day =$0.32854 Polyphase Service per meter/day =$0.65708	**Summer**		-				$0.24176		
		Winter		-				$0.16445		
A-1 TOU	Single Phase Service per meter/day =$0.32854 Polyphase Service per meter/day =$0.65708	**Summer**		-			On peak	$0.26241		
							Part Peak	$0.25308		
							Off Peak	$0.22468		
		Winter		-			Part Peak	$0.17479		
							Off Peak	$0.15497		
A-6 TOU	Single phase service per meter/day =$0.32854; Polyphase service per meter/day =$0.65708. Plus Meter charge =$0.20107per day for A6 or A6X; =$0.05914 per day for A6W[6/]	**Summer**		-			On peak	$0.61173		
							Part Peak	$0.28551		
							Off Peak	$0.15804		
		Winter		-			Part Peak	$0.18082		
							Off Peak	$0.14804		
A-10 (Table A)	$4.59959 per meter per day	**Summer**		$16.23	$15.22	$10.85		$0.16116	$0.14936	$0.12137
		Winter		$8.00	$8.20	$6.29		$0.11674	$0.11069	$0.09583
A-10 TOU (Table B)	$4.59959 per meter per day	**Summer**		$16.23	$15.22	$10.85	Peak	$0.17891	$0.16420	$0.13481
							Part-Peak	$0.17087	$0.15846	$0.12958
							Off-Peak	$0.14642	$0.13650	$0.10973
		Winter		$8.00	$7.35	$6.29	Part-Peak	$0.12750	$0.11949	$0.10392
							Off-Peak	$0.10654	$0.10231	$0.08816
E-19 TOU	$3.94267 per meter per day	**Summer**	Max. Peak	$9.71	$8.91	$7.03	Peak	$0.14026	$0.13861	$0.09129
			Part Peak	$3.33	$3.06	$2.78	Part Peak	$0.09916	$0.09219	$0.08665
			Maximum	$16.04	$12.08	$7.87	Off Peak	$0.07512	$0.07456	$0.07043
		Winter	Part Peak	$0.24	$0.46	$0.00	Part Peak	$0.09451	$0.09196	$0.08500
			Maximum	$9.71	$8.63	$7.87	Off Peak	$0.07885	$0.07787	$0.07214

Figure 13: PG&E A-10 tariffs

A-1, A-10 and E-19 Time-of-Use Periods

Summer Period A (May-October)

Peak:	12:00 noon to 6:00 pm	Monday through Friday (except holidays)
Partial-Peak:	8:30 am to 12:00 noon 6:00 pm to 8:30 pm	Monday through Friday (except holidays) Monday through Friday (except holidays)
Off-Peak:	8:30 pm to 8:30 am All Day	Monday through Friday (except holidays) Saturday, Sunday, and Holidays

Winter Period B (November-April)

Partial-Peak:	8:30 am to 8:30 pm	Monday through Friday (except holidays)
Off-Peak:	8:30 pm to 8:30 am All Day	Monday through Friday (except holidays) Saturday, Sunday, and Holidays

Figure 14: PG&E Time periods

Electricity Rates

	F1	On	Mid	Off
1	January	0	0.09451	0.07885
2	February	0	0.09451	0.07885
3	March	0	0.09451	0.07885
4	April	0	0.09451	0.07885
5	May	0.14026	0.09916	0.07512
6	June	0.14026	0.09916	0.07512
7	July	0.14026	0.09916	0.07512
8	August	0.14026	0.09916	0.07512
9	September	0.14026	0.09916	0.07512
10	October	0.14026	0.09916	0.07512
11	November	0	0.09451	0.07885
12	December	0	0.09451	0.07885

Monthly Access Fee

	F1	F2
1	UtilElectric	118.28
2	UtilNGbasic	64.4808
3	UtilNGforDG	0
4	UtilNGforABS	0
5	UtilDiesel	0

Monthly Demand Rates

	F1	coincident	noncoincident	onpeak	midpeak	offpeak
1	January	0	9.71	0	0.24	0
2	February	0	9.71	0	0.24	0
3	March	0	9.71	0	0.24	0
4	April	0	9.71	0	0.24	0
5	May	0	16.04	9.71	3.33	0
6	June	0	16.04	9.71	3.33	0
7	July	0	16.04	9.71	3.33	0
8	August	0	16.04	9.71	3.33	0
9	September	0	16.04	9.71	3.33	0
10	October	0	16.04	9.71	3.33	0
11	November	0	9.71	0	0.24	0
12	December	0	9.71	0	0.24	0

List of Hours

	F1	F2	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Summer	peak	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	2	2	2	3	3	3
2	Summer	week	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	2	2	2	3	3	3
3	Summer	weekend	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
4	Winter	peak	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
5	Winter	week	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
6	Winter	weekend	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Figure 15: Tariff tables in DER-CAM

Setting the marginal CO_2 emissions as well as CO_2 emissions from burning fuel (Figure 16) can also be changed in this segment. In this particular case the CO_2 emissions rate are obtained from CAISO (Californian Independent System Operator) in combination with the U.S. Energy Information Administration (EIA), and the fuel emissions rate are estimated using average heating content values obtained from EIA.

Marginal CO2 Emissions

	F1	1	2	3	4	5	6	7	8	9	10	11	12
1	January	0.481746583	0.480936526	0.494054128	0.486273062	0.485150078	0.509145785	0.525330791	0.516663906	0.507155512	0.497523708	0.504104566	0.503
2	February	0.504965908	0.521956621	0.507946724	0.53068471	0.516157864	0.506402525	0.507069358	0.5293347	0.509769645	0.503835412	0.492813116	0.486
3	March	0.5053582	0.556058867	0.557902993	0.547899422	0.529392109	0.520293926	0.500453832	0.501196474	0.486287422	0.484293627	0.474786678	0.482
4	April	0.524414291	0.546542175	0.616499733	0.604602223	0.559804894	0.502737779	0.532098798	0.509197359	0.50796506	0.501644473	0.502819122	0.506
5	May	0.531052814	0.564394651	0.580164246	0.565106113	0.544601901	0.495560258	0.522344909	0.51348947	0.499671515	0.485817883	0.483296476	0.491
6	June	0.500379835	0.485026777	0.539777959	0.538613995	0.428604814	0.49317292	0.513156044	0.509790898	0.460039986	0.483845887	0.496333347	0.469
7	July	0.482737281	0.496777447	0.48369147	0.490346581	0.504696274	0.492577859	0.492545235	0.511379084	0.517888908	0.517763346	0.516429018	0.538
8	August	0.519714278	0.511717295	0.52002478	0.518496413	0.534491071	0.518157568	0.51258708	0.491244194	0.505201984	0.519342537	0.535581403	0.540
9	September	0.511319061	0.480955649	0.492512363	0.511786053	0.485706068	0.532907631	0.50653321	0.516833168	0.5269343	0.518591994	0.517868893	0.540
10	October	0.489221462	0.495747928	0.50143607	0.506515208	0.516648487	0.502418965	0.529823131	0.529581737	0.513463098	0.504507803	0.51513967	0.510
11	November	0.503811212	0.499479136	0.503063669	0.514076285	0.501754091	0.492877271	0.520685843	0.502337031	0.523283088	0.508793314	0.510443889	0.503
12	December	0.486977303	0.50697829	0.505844562	0.502001081	0.51666905	0.501390618	0.523289251	0.508057703	0.517834019	0.503992296	0.497395331	0.505

Fuel CO2 Emissions Rate

	F1	F2
1	NGbasic	0.18084
2	NGforDG	0.18084
3	NGforAbs	0.18084
4	Diesel	0.24948
5	BioDiesel	0.0757
6	Other	0

Figure 16: CO_2 emissions tables in DER-CAM

Given that the purpose of this initial run is to determine only the reference costs for the investment analysis, the **Technology** segment does not require any changes unless there is already existing equipment at the site. In this particular case we will assume this is not the case, and will address DER technologies later on. Likewise, **Energy Management and Resiliency** options will not be considered in this reference run.

Once all the input parameters have been revised, click on in the toolbar to run the optimization. The results window will appear shortly after (Figure 17).

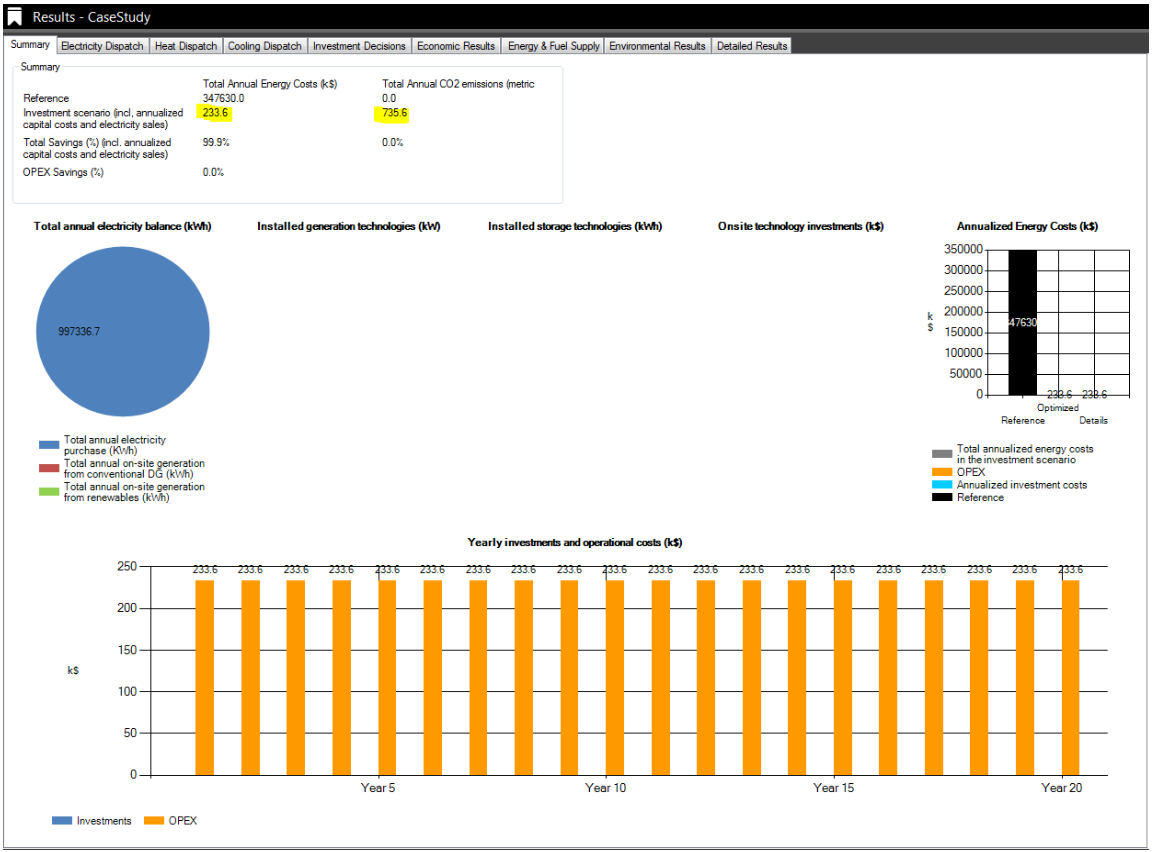


Figure 17: Result View, Summary Sheet

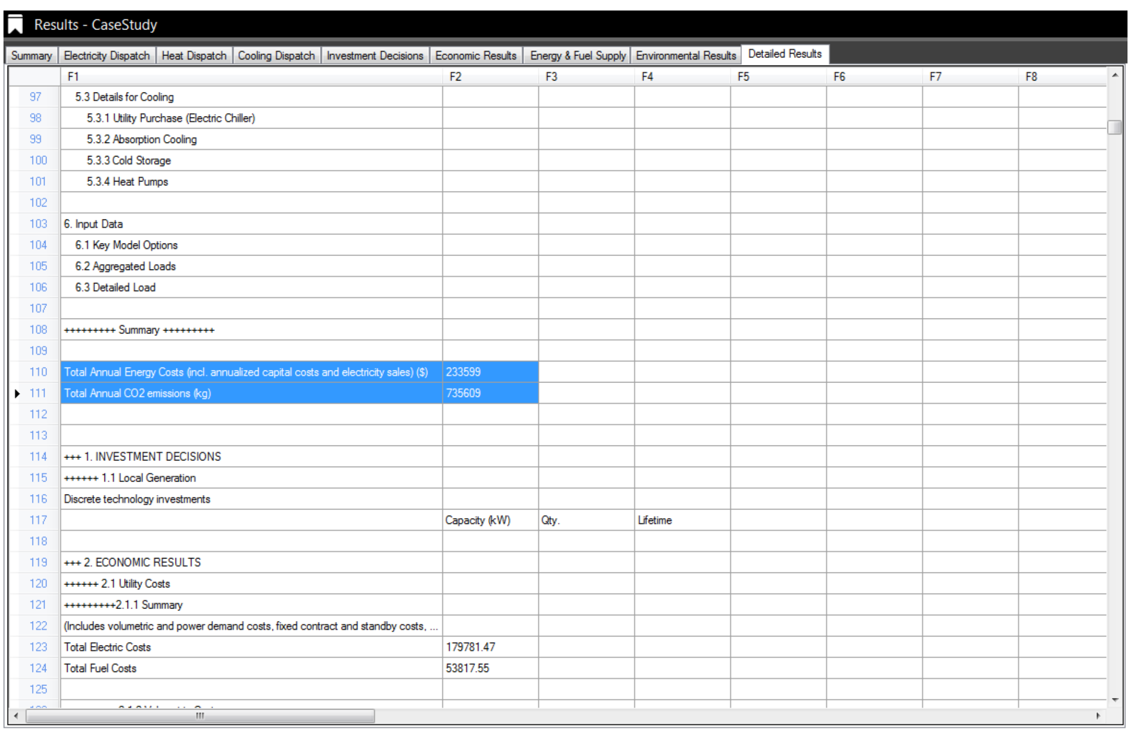


Figure 18: Results View, Detailed Results Sheet

The base case cost and the base case CO_2 are the highlighted values, respectively $233599 and 735609 kg. Now that the values of these parameters are obtained we can insert them in the **Parameter Table** under **Global Settings**. Note that you should add 1 % of their values to guarantee feasibility, which is the default solver precision.

4. Cost minimization

After performing the base case or reference case, investment analysis may be conducted. To do this, we have updated the BaseCaseCost and BaseCaseCO2 parameters in the **Parameter Table** found in the **Global Settings** segment, and other financial parameters must now be defined, including the project "InterestRate" and the "MaxPaybackPeriod". It should be noted that whenever performing investment analysis all financial constrains must be verified, regardless of the objective being economic or environmental. For this reason, if the maximum project payback is set to be too short, the investments may be limited or inexistent. In this case study we have set the maximum payback period equal to 10 years and the interest rate to be 5% (Figure 19).

To enable investments we now update the "DiscreteInvest" and "ContinuousInvest" parameters, which will generically allow investments all technologies that fall within these groups (Figure 19). Further down we will refine this by defining which technologies we are interested in within these groups.

1	IntRate	0.05
2	Standby	0
3	Contrct	0
4	turnvar	0
5	CO2Tax	0.272727
6	macroeff	0.34
7	cooleff	0
8	BaseCaseCost	235000
9	BaseCaseCO2	740000
10	MaxPaybackPeriod	10

DiscreteInvest	1
ContinuousInvest	1

Figure 19: Parameter and Option Table

Given that all other relevant areas were defined to calculate the reference cost, we can now focus on the **Technologies** section, starting with discrete technologies.

Under **Generator constraints** we find the table that will allow us to enable or disable specific technologies depending on our needs (Figure 23). Please note that the technologies where "MaxAnnualHours" is set to 0 are disabled and cannot be selected in the optimization. In this case study we are only considering the first 14 technologies, as seen in Figure 21, and have allowed them to run freely during all 8760 hours of the year. Furthermore, we do not want to force and number of technologies to be installed, but rather want DER-CAM to freely choose on the optimum number of technologies. This is done by setting "ForcedInvest" to zero, as well as "ForcedNumber" (Figure 21). In this case study we are using the default techno-economic parameters for all 14 technologies enabled, but at any moment the existing values can be updated to better reflect any specific project needs (Figure 20).

After setting the parameters for the discrete technologies we go over to continuous technologies. In our case study we will focus specifically on stationary batteries, heat storage, PV and air source heat pumps. This is done by allowing each of these technologies to be freely selected by DER-CAM, since "ForcedInvest", and "ForcedCapacity" are set to 0. All technologies not considered in this group are disabled by forcing the capacity to be 0: "ForcedInvest" is set to 1, and "ForcedCapacity" is set to 0 (Figure 22).

Again, we are using the default techno-economic characteristics for all these technologies, but they can be customized feely at any time.

DER Technologies Info

	F1	maxp	lifetime	capcost	OMFix	OMVar	SprintCap	SprintHours	Fuel	Type	efficiency	efficiency_var	alpha	Chpenable	BackupOnly	SGIPIncentive	AllowFeedIn	N
1	ICE-small-20_______	60	20	2098	0	0.021	60	0	3	4	0.29	0	0	0	0	0	0	0
2	ICE-med-20_________	250	20	1143	0	0.015	250	0	3	4	0.3	0	0	0	0	0	0	0
3	GT-20_____________	1000	20	2039	0	0.011	1000	0	3	2	0.22	0	0	0	0	0	0	0
4	MT-small-20________	60	10	2116	0	0.017	60	0	3	5	0.28	0	0	0	0	0	0	0
5	MT-med-20__________	150	10	1723	0	0.017	150	0	3	5	0.29	0	0	0	0	0	0	0
6	FC-small-20________	100	10	4969	0	0.033	100	0	3	1	0.4	0	0	0	0	0	0	0
7	FC-med-20__________	250	10	3981	0	0.033	250	0	3	1	0.4	0	0	0	0	0	0	0
8	ICE-HX-small-20_____	60	20	2760	0	0.021	60	0	3	4	0.29	0	1.73	1	0	0	0	0
9	ICE-HX-med-20_______	250	20	1681	0	0.015	250	0	3	4	0.3	0	1.48	1	0	0	0	0
10	GT-HX-20___________	1000	20	2794	0	0.011	1000	0	3	2	0.22	0	1.96	1	0	0	0	0
11	MT-HX-small-20______	60	10	2377	0	0.017	60	0	3	5	0.28	0	1.8	1	0	0	0	0
12	MT-HX-med-20________	150	10	1935	0	0.017	150	0	3	5	0.29	0	1.4	1	0	0	0	0
13	FC-HX-small-20______	100	10	5618	0	0.033	100	0	3	1	0.4	0	1	1	0	0	0	0
14	FC-HX-med-20________	250	10	4629	0	0.033	250	0	3	1	0.4	0	1	1	0	0	0	0
15	FC-HX-small-20-wSGIP	100	10	2270	0	0.033	100	0	3	1	0.4	0	1	1	0	1	0	0
16	FC-HX-med-20-wSGIP__	250	10	3821	0	0.033	250	0	3	1	0.4	0	1	1	0	1	0	0
17	ICE-small-30_______	60	20	1587	0	0.021	60	0	3	4	0.29	0	0	0	0	0	0	0
18	ICE-med-30_________	250	20	865	0	0.015	250	0	3	4	0.3	0	0	0	0	0	0	0
19	GT-30_____________	1000	20	1932	0	0.011	1000	0	3	2	0.22	0	0	0	0	0	0	0
20	MT-small-30________	60	10	1410	0	0.017	60	0	3	5	0.31	0	0	0	0	0	0	0
21	MT-med-30__________	150	10	1148	0	0.017	150	0	3	5	0.33	0	0	0	0	0	0	0
22	FC-small-30________	100	10	3605	0	0.033	100	0	3	1	0.46	0	0	0	0	0	0	0
23	FC-med-30__________	250	10	2889	0	0.033	250	0	3	1	0.46	0	0	0	0	0	0	0
24	ICE-HX-small-30_____	60	20	2088	0	0.021	60	0	3	4	0.29	0	1.73	1	0	0	0	0
25	ICE-HX-med-30_______	250	20	1271	0	0.015	250	0	3	4	0.3	0	1.48	1	0	0	0	0
26	GT-HX-30___________	1000	20	2647	0	0.011	1000	0	3	2	0.22	0	1.96	1	0	0	0	0
27	MT-HX-small-30______	60	10	1584	0	0.017	60	0	3	5	0.31	0	1.8	1	0	0	0	0
28	MT-HX-med-30________	150	10	1290	0	0.017	150	0	3	5	0.33	0	1.4	1	0	0	0	0
29	FC-HX-small-30______	100	10	4192	0	0.033	100	0	3	1	0.46	0	1	1	0	0	0	0
30	FC-HX-med-30________	250	10	3359	0	0.033	250	0	3	1	0.46	0	1	1	0	0	0	0
31	MT-HX-small-30-wSGIP	60	10	1424	0	0.017	60	0	3	5	0.33	0	1.8	1	0	1	0	0
32	MT-HX-med-30-wSGIP__	150	10	1130	0	0.017	150	0	3	5	0.33	0	1.4	1	0	1	0	0
33	FC-HX-small-30-wSGIP	100	10	4032	0	0.033	100	0	3	1	0.46	0	1	1	0	1	0	0
34	FC-HX-med-30-wSGIP__	250	10	3199	0	0.033	250	0	3	1	0.46	0	1	1	0	1	0	0
35	s35XXXXXXXXXXXXX...	1	1	1	1	1	1	0	3	1	1	0	0	0	0	0	0	0
36	s36XXXXXXXXXXXXX...	1	1	1	1	1	1	0	3	1	1	0	0	0	0	0	0	0
37	s37XXXXXXXXXXXXX...	1	1	1	1	1	1	0	3	1	1	0	0	0	0	0	0	0
38	s38XXXXXXXXXXXXX...	1	1	1	1	1	1	0	3	1	1	0	0	0	0	0	0	0
39	ICE-P150-2-DIESEL--	120	20	200	0	0.015	120	0	4	3	0.34	0	0	0	1	0	0	0
40	ICE-P250HE2-DIESEL--	200	20	168	0	0.013	200	0	4	3	0.32	0	0	0	1	0	0	0

Figure 20: DER Technologies Info

Generator Constraints

	F1	MaxAnnualHours	MinLoad	ForcedInvest	ForcedNumber	Existing
1	ICE-small-20________	8760	0.25	0	0	0
2	ICE-med-20__________	8760	0.25	0	0	0
3	GT-20_______________	8760	0.5	0	0	0
4	MT-small-20_________	8760	0.5	0	0	0
5	MT-med-20___________	8760	0.5	0	0	0
6	FC-small-20_________	8760	0.9	0	0	0
7	FC-med-20___________	8760	0.9	0	0	0
8	ICE-HX-small-20_____	8760	0.25	0	0	0
9	ICE-HX-med-20_______	8760	0.25	0	0	0
10	GT-HX-20____________	8760	0.5	0	0	0
11	MT-HX-small-20______	8760	0.5	0	0	0
12	MT-HX-med-20________	8760	0.5	0	0	0
13	FC-HX-small-20______	8760	0.9	0	0	0
14	FC-HX-med-20________	8760	0.9	0	0	0
15	FC-HX-small-20-wSGIP	0	0.9	0	0	0
16	FC-HX-med-20-wSGIP__	0	0.9	0	0	0
17	ICE-small-30________	0	0.25	0	0	0
18	ICE-med-30__________	0	0.25	0	0	0
19	GT-30_______________	0	0.5	0	0	0
20	MT-small-30_________	0	0.5	0	0	0
21	MT-med-30___________	0	0.5	0	0	0
22	FC-small-30_________	0	0.9	0	0	0
23	FC-med-30___________	0	0.9	0	0	0
24	ICE-HX-small-30_____	0	0.25	0	0	0
25	ICE-HX-med-30_______	0	0.25	0	0	0
26	GT-HX-30____________	0	0.5	0	0	0
27	MT-HX-small-30______	0	0.5	0	0	0
28	MT-HX-med-30________	0	0.5	0	0	0
29	FC-HX-small-30______	0	0.9	0	0	0
30	FC-HX-med-30________	0	0.9	0	0	0
31	MT-HX-small-30-wSGIP	0	0.5	0	0	0
32	MT-HX-med-30-wSGIP__	0	0.5	0	0	0
33	FC-HX-small-30-wSGIP	0	0.9	0	0	0
34	FC-HX-med-30-wSGIP__	0	0.9	0	0	0
35	s35XXXXXXXXXXXXXXXXX	0	0.5	0	0	0
36	s36XXXXXXXXXXXXXXXXX	0	0.5	0	0	0
37	s37XXXXXXXXXXXXXXXXX	0	0.5	0	0	0
38	s38XXXXXXXXXXXXXXXXX	0	0.5	0	0	0
39	ICE-P150-2-DIESEL---	8760	0.5	0	0	0
40	ICE-P250HE2-DIESEL--	8760	0.5	0	0	0

Figure 21: Generator Constraints

Continuous Investment Parameters

	F1	FixedCost	VariableCost	Lifetime	FixedMaintenance
1	ElectricStorage	295	300	5	0
2	HeatStorage	10000	50	17	0
3	ColdStorage	10000	50	17	0
4	FlowBatteryEnergy	0	220	10	0
5	FlowBatteryPower	0	2125	10	0
6	AbsChiller	93912	685.22	20	1.88
7	AbsRefrigeration	93912	753.74	20	2.07
8	PV	3851.25	3237	30	0.25
9	SolarThermal	0	500	15	0.5
10	EVs1	100	5	1	0
11	AirSourceHeatPump	0	70	10	0.52
12	GroundSourceHeatPump	0	79.74	10	0.32

Figure 22: Forced Investment parameters for continuous technologies

At this point we are not considering any energy management options or resiliency issues. Therefore, to perform the investment analysis we simply launch the optimization process.

Once the optimization is completed, in addition to visualizing results through our GUI, you may also choose to e-mail yourself results by clicking on . Please note that macros should be enabled in order for this document to work properly.

The result sheet obtained is shown on Figure 23. On Figure 24, where savings are shown in detail, it can be seen that the total annual energy cost decreased from 235000$ to 173800$, even taking into account the annualized investment cost of new technologies. The operational savings obtained are 56%: this has to do with the fact that less electricity is bought from the grid and on-site cheaper generation is used instead. In short, we have increased capital costs by investing in new technologies, but our annual operational expenditures are now lower, and the savings obtained are enough to repay for investments within the boundaries set by all financial constraints. It can also be seen from Figure 24 that CO_2 emissions are lowered by 45% in the investment case. This decrease in emissions is mainly due to the green energy generated by the PV panels. Details about the annual electricity balance and the annualized energy cost are shown on Figure 25. The investment decisions are shown on Figure 26.

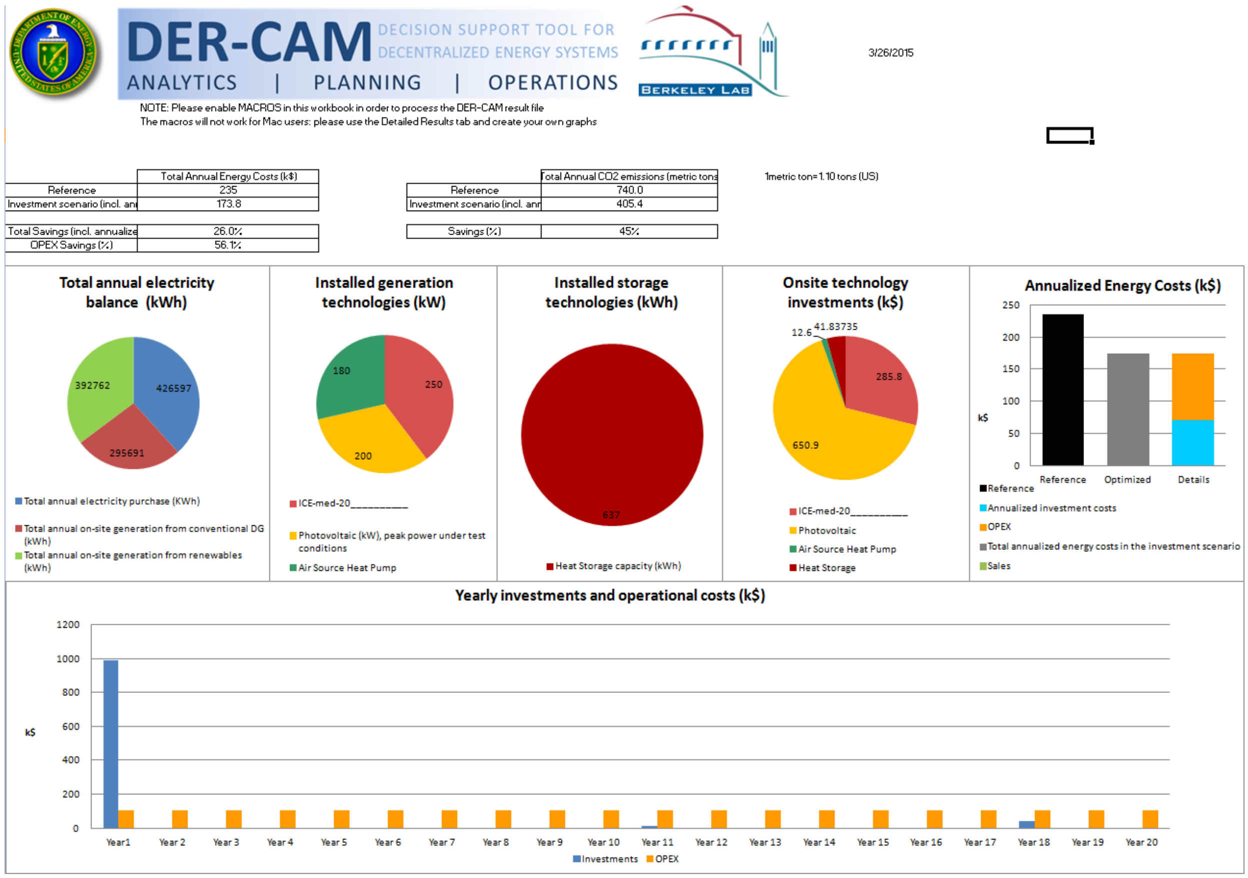


Figure 23: Investment summary section in the result sheet

	Total Annual Energy Costs (k$)
Reference	235
Investment scenario (incl. annu	173.8
Total Savings (incl. annualized	26.0%
OPEX Savings (%)	56.1%

	Total Annual CO2 emissions (metric tons)
Reference	740.0
Investment scenario (incl. annu	405.4
Savings (%)	45%

Figure 24: Annual Savings of energy costs and CO2 emissions

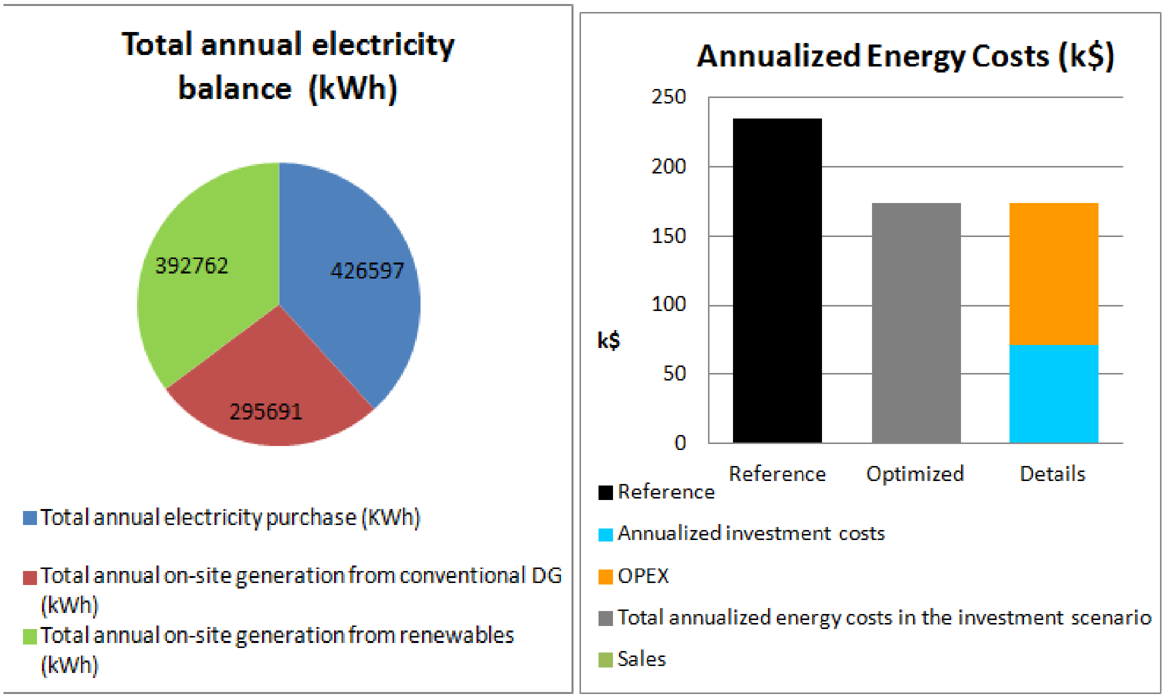


Figure 25: Annual electricity balance and energy costs

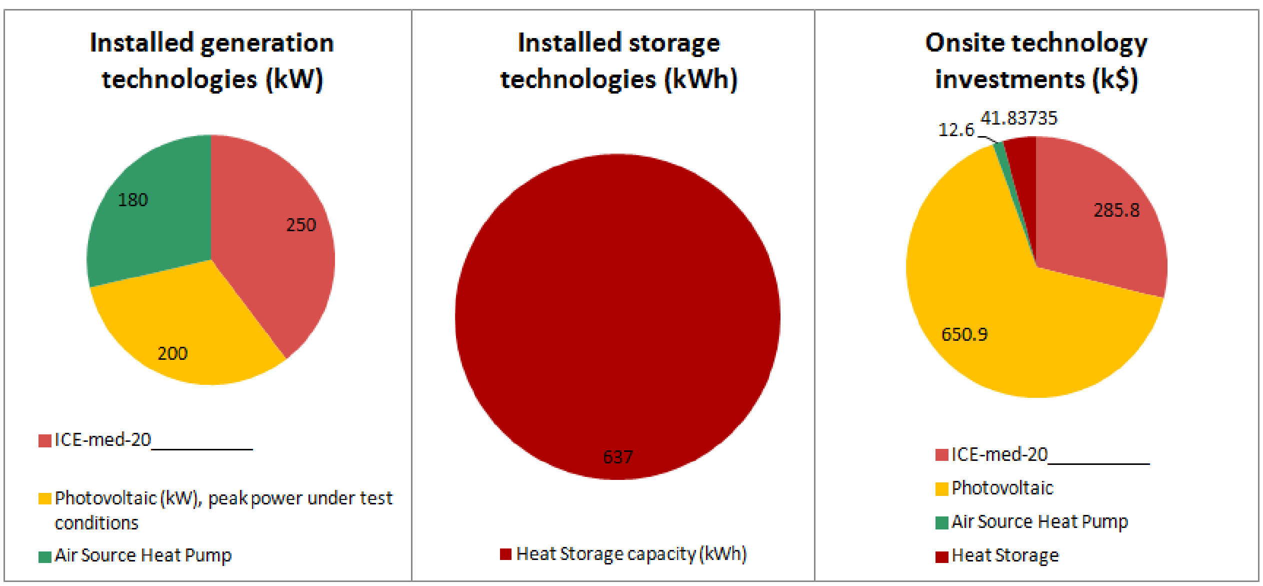


Figure 26: Investments capacities and upfront capital costs

It can be seen that the investment suggested by DER-CAM includes 180 kW of PV panels, a 250kW internal combustion engine, an air source heat pump of 180 kW, and a heat storage device with an energy capacity of 637 kWh. No investments in stationary batteries are suggested. Of all installed technologies the investment in PV is the most capital intensive as shown on the graph on the right side of Figure 26.

Figure 27 shows the dispatch for electricity on a week-day in January. Similar profiles can be found for other day-types during different months and for other end-uses by browsing through the tabs and using the dropdown boxes above the chart. It can be seen that with the new dispatch about the same amount of energy is bought from the grid, but with a very different scheduling. The electricity consumption of the heat pump is highest during off peak hours in the early morning in order to lower the electricity bill, and the utility purchase (in green) is now lower in terms of power consumption when compared to the base case (black dashed line), which significantly contributes to lower power demand charges.

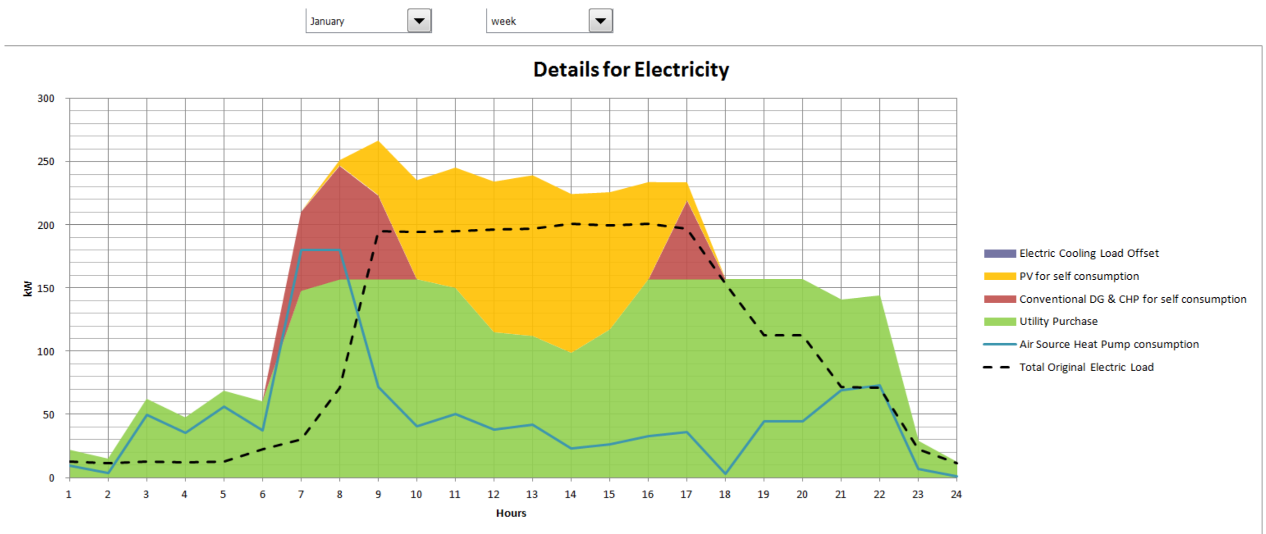


Figure 27: Electricity Dispatch

5. CO_2 minimization

Changing the objective function to CO_2 minimization is extremely simple and can be done using the "MinimizeCO2" parameter in the **Parameter Table** of **Global Options** (Fig 28). Since both the reference costs and investment options have been defined, no other changes are required and the CO_2 minimization run can now be performed

11	VaryPrice	0
12	CHP	0
13	CO2Tax	0
14	MinimizeCO2	1
15	ZNEB	0
16	MultiObjective	0
17	DiscreteElecStorage	0

Figure 28: Options Table

In this case results show that the total annual costs have only decreased by 12.4% in comparison to the reference costs (Figure 29). As expected, this is a lower decrease than in the cost optimization case but it still verifies the financial constraints imposed in the model, as the annual operational expenses have decreased strongly, by 77.7%, even more than in the cost minimization case.

When choosing CO_2 minimization, the split between investment and OPEX is very different from the cost minimization run, as seen by analyzing the right graphs of Figure 25 and Figure 30: Annual electricity balance and energy costs for the CO2 minimization scenario

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In this run the annual CO_2 emissions have now decreased by 77%, mainly due to the large investment in PV. It should be noted that because the maximum payback period was set to 10 years the total investment was relatively limited. If the maximum payback period was increased other significant investments with potential to reduce CO_2 would be expected.

	Total Annual Energy Costs (k$)
Reference	235
Investment scenario (incl. annu	205.8
Total Savings (incl. annualized c	12.4%
OPEX Savings (%)	77.7%

	Total Annual CO2 emissions (metric tons)
Reference	740.0
Investment scenario (incl. annua	166.6
Savings (%)	77%

Figure 29: Annual savings for costs and CO2 emissions for the CO2 minimization scenario

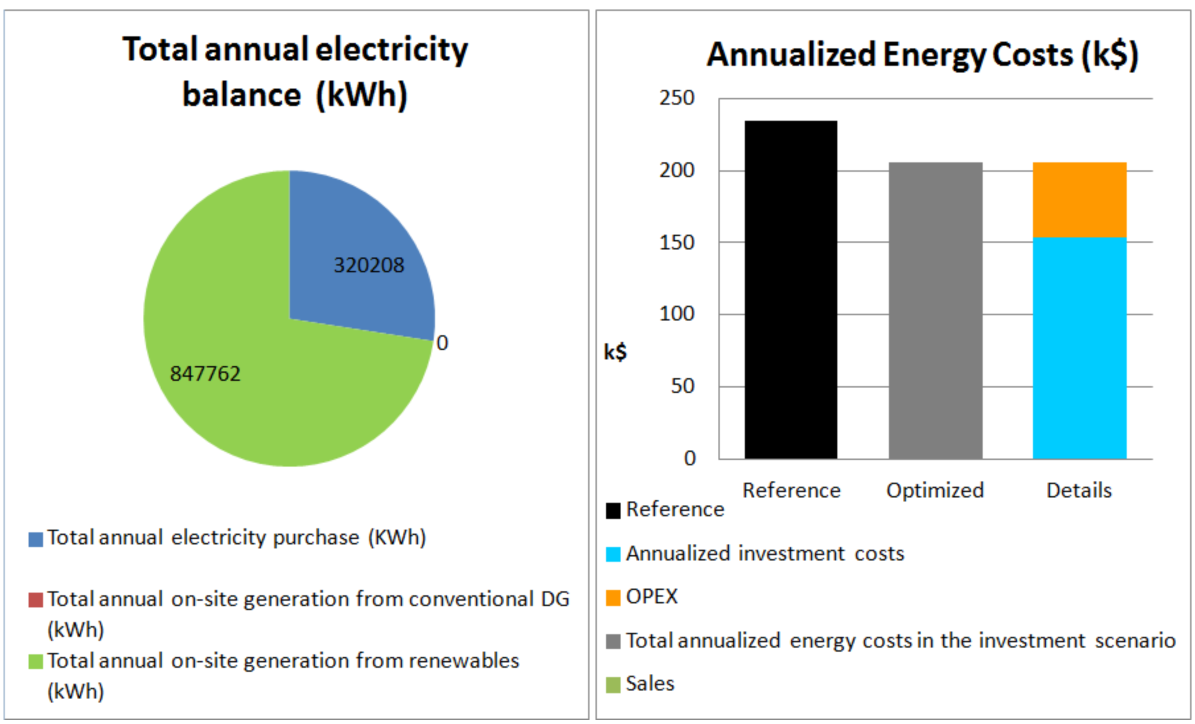

Figure 30: Annual electricity balance and energy costs for the CO_2 minimization scenario

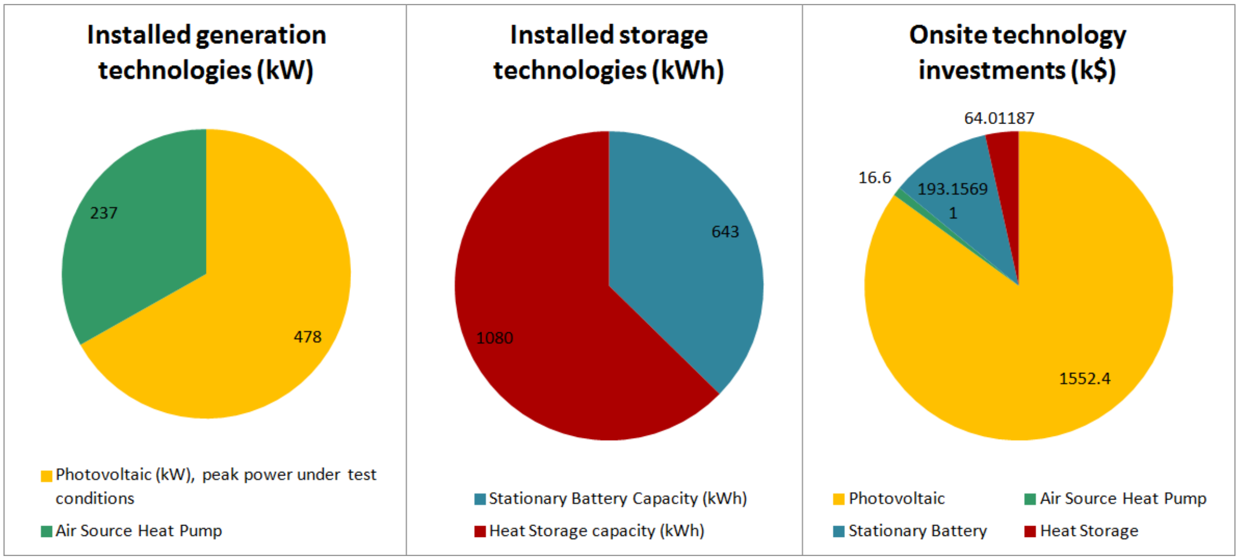

Figure 30: Investments capacities and upfront capital costs for the CO2 minimization scenario

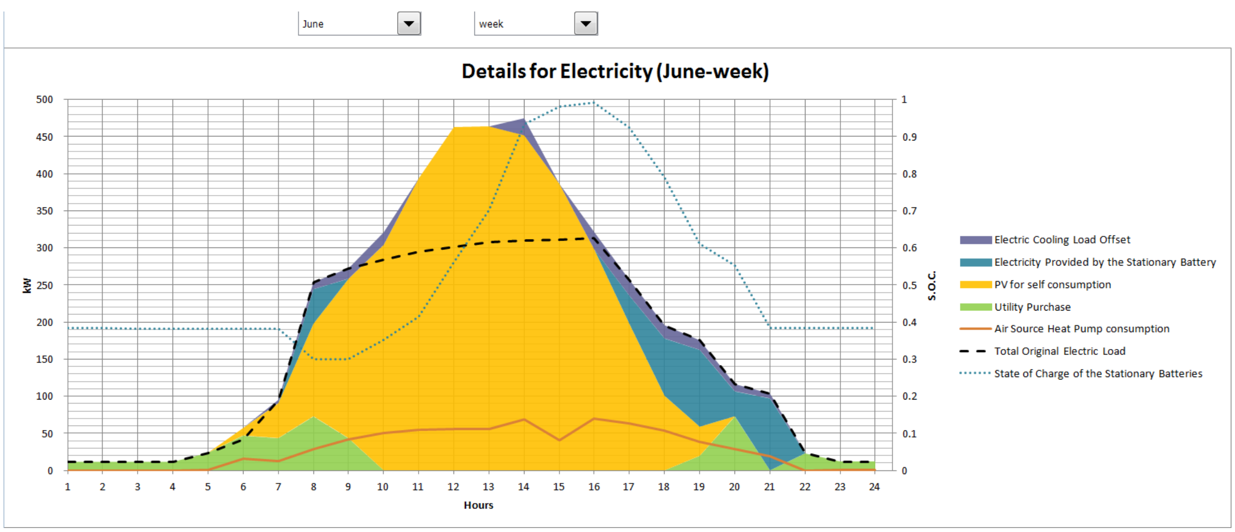

Figure 31: Electricity dispatch for the CO2 minimization scenario

In the CO_2 minimization case DER-CAM now suggests to invest in 478 kW of PV, 237kW of air source heat pump, a 1080 kWh heat storage tank, and a stationary battery of 643 kWh. In comparison with the cost minimization case, we see that the internal combustion engine is no longer present and stationary batteries are now included in the solution.
This choice is justified in the CO_2 minimization as batteries complement the high capacity of installed PV. Please note that in this case sales to the utility are not.

Figure 31 shows the dispatch for electricity for a week day in June. As it can be observed, PV is now being used to supply a large portion of the electricity load and is also being used to charge the batteries used later when the solar radiation drops.

6. Multi objective optimization

As mentioned earlier, three reference runs must be performed prior to conducting multi-objective optimizations. These are the reference case, cost minimization, and CO_2 minimization runs described above. Performing these runs allows setting the scaling factors for the cost and CO_2 objectives, “MultiObjectiveMaxCosts” and “MultiObjectiveMaxCO2”. These values are obtained by finding the costs of a CO_2 minimization run, and the CO_2 emissions of a cost minimization run, respectively.

In our case study we have already obtained all of the necessary information given the runs performed above, and for this reason we now must only update the scaling factors in the **Parameters Table** found in the **Global Settings** segment.

Once this information has been introduced, we may now choose how each of the cost and CO_2 objectives must be weighted, by setting the “MultiObjectiveWCosts” and “MultiObjectiveWCO2”, as shown in Fig. 33. These reflect the relative preference of the user over the criteria.
Changing the goal to a multi-objective approach is done with the **Options Table**, by setting “MultiObjective” to 1.

	F1	F2
1	IntRate	0.05
2	Standby	0
3	Contrct	0
4	turnvar	0
5	CO2Tax	0.272727
6	macroeff	0.34
7	cooleff	0
8	BaseCaseCost	235000
9	BaseCaseCO2	740000
10	MaxPaybackPeriod	10
11	FractionBaseLoad	0.5
12	FractionPeakLoad	0.1
13	ReliabilityDER	0.9
14	MaxSpaceAvailablePVSolar	1620000
15	PeakPVEfficiency	0.1529
16	MultiObjectiveMaxCosts	205800
17	MultiObjectiveMaxCO2	405400
18	MultiObjectiveWCosts	0.5
19	MultiObjectiveWCO2	0.5
20	ZNEBsolarAreaMultiplier	200
21	ZNEBCostsMultiplier	2
22	BldgShellLifetime	20
23	MinAnnDERGen	0
24	MinAnnRENGen	0

Figure 32: Parameters table for multi-objective run

For this case study several runs were done with different settings of weights and the results are shown on Figure 36. There is a clear trade-off between cost and CO_2 minimization. It is very interesting to see that for only a small increase in the minimal costs of 3%, emissions are lowered by 40%.

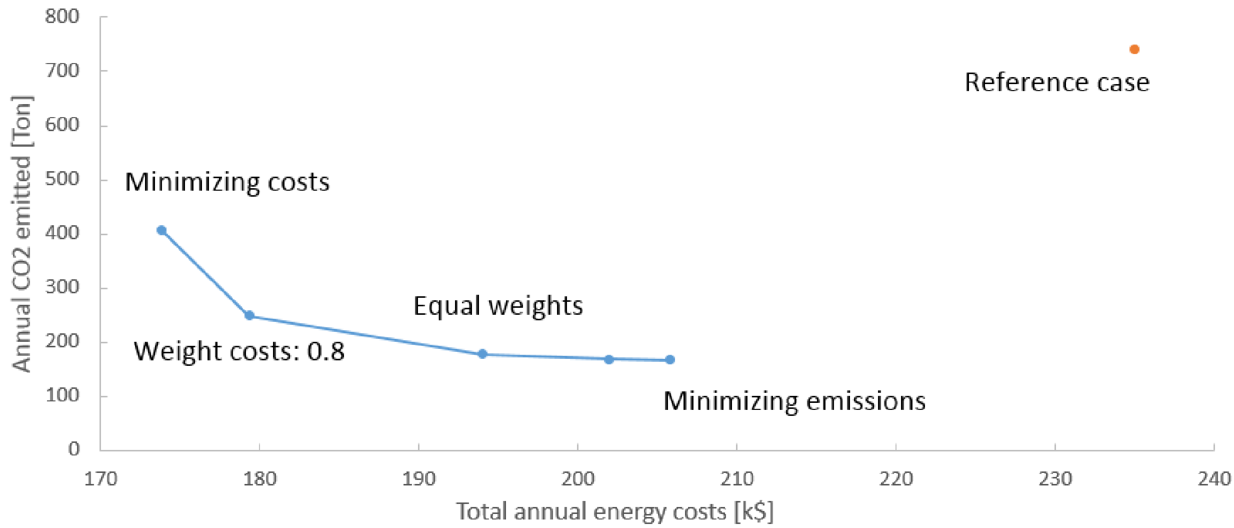

Figure 33: Efficiency frontier

7. Cost minimization with existing technologies, forced investments and grid outages

In this section of the case study we assume that 100 kW of PV capacity are already installed on-site although we are willing to consider additional PV. Additionally, we want to force exactly 500 kWh of stationary battery capacity. Finally, to test the resilience of our microgrid we will simulate an outage from 5 pm to 8.30 pm during a weekday in September.

First of all, because some equipment is pre-installed on-site, we need to run the base case again taking the existing equipment into account. “DiscreteInvest” and “ContinuousInvest” are set to 0 as in the initial reference case because no new investment is allowed, except 100 kW of PV are now forced in the solution by setting “ForcedCapacity” to 100 and defining it as “Existing”. Figure 34 shows the setting of the continuous technologies **Forced Investment Parameters**.

	F1	ForcedInvest	ForcedInvestCapacity	Existing
1	ElectricStorage	0	0	0
2	HeatStorage	1	0	0
3	ColdStorage	1	0	0
4	FlowBatteryEnergy	1	0	0
5	FlowBatteryPower	1	0	0
6	AbsChiller	1	0	0
7	AbsRefrigeration	1	0	0
8	PV	0	100	1
9	SolarThermal	1	0	0
10	EVs1	1	0	0
11	AirSourceHeatPump	1	0	0
12	GroundSourceHeatPump	1	0	0

Figure 34: Continuous technologies investment constraint

Also, outages costs need to be taken into account in this base case run. To model an outage three steps are required. First of all we set the number of emergency weekdays in September equal to 1 and decrease the amount of 'normal' weekdays from 18 to 17 (Fig 36).

	F1	peak	week	weekend	emergency-week	emergency-peak	emergency-weekend
1	January	3	20	8	0	0	0
2	February	3	17	8	0	0	0
3	March	3	18	10	0	0	0
4	April	3	19	8	0	0	0
5	May	3	20	8	0	0	0
6	June	3	17	10	0	0	0
7	July	3	20	8	0	0	0
8	August	3	18	9	0	0	0
9	September	3	17	9	1	0	0
10	October	3	20	8	0	0	0
11	November	3	18	9	0	0	0
12	December	3	19	9	0	0	0

Figure 35: Number of days

Secondly, we set the hours during which the outage will occur from 5 pm until 8.30 pm (Figure 36).

	F1	F2	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	January	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	February	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	March	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	April	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5	May	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
6	June	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	July	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	August	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
9	September	emergency-week	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0.5	1	1	1
10	October	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	November	emergency-week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Figure 36: Electric utility availability

Lastly, we chose to allow curtailment of electric loads by setting the maximum hours of curtailment higher than 0 for all three priority levels and we assign a variable cost to them. In this case we are not interested in heating load curtailments and leave all the values of those parameters to zero.

It should be noted that the process of valuation of different load curtailments is a very sensitive matter and will have a very significant impact on results. In order to properly assess these numbers it is important to understand all costs that may incur due to loss of load, including salaries of staff that may be sent home, costs of perishable goods, servers, or any other relevant costs. While some tools may be already available to estimate these costs (e.g. www.icecalculator.com), finding realistic values requires careful analysis and understanding of the site being studied.

	F1	VariableCost	MaxCurtailment	MaxHours
1	lowCR	3.25	0.2	8760
2	midCR	26.75	0.7	8760
3	highCR	50	0.1	8760

Figure 37: Curtailment parameters

The total annual energy costs and total annual CO_2 emissions for the base case are shown on Figure 38 and will be used as reference for the investment runs. The base case cost is now significantly higher due to the cost of curtailment, especially of mid and high priority load. The electricity dispatch for the emergency weekday in September is shown on Figure 39. It can be seen that curtailment has occurred during the outage.

108	+++++++++ Summary +++++++++	
109		
110	Total Annual Energy Costs (incl. an...	244150
111	Total Annual CO2 emissions (kg)	631988

Figure 38: Results summary

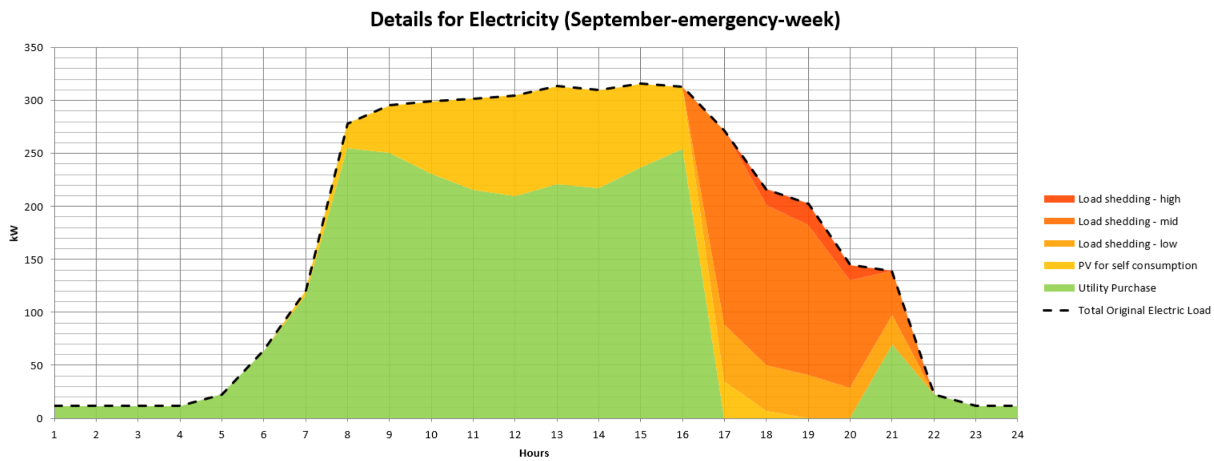

Figure 39: Electricity dispatch for the base case with outage

After obtaining the new reference costs the investment run can be launched. We now allow new investments and set “ContinuousInvest” and “DiscreteInvest” to 1 in the **Parameter Table** found under **Global Settings**. In this case we have kept all technology options considered in the initial cost minimization run, but force a stationary battery of exactly 500 kWh. We also allow additional PV investment beyond the pre-existing 100 kW (Fig 41).

	F1	ForcedInvest	ForcedInvestCapacity	Existing
1	ElectricStorage	1	500	0
2	HeatStorage	0	0	0
3	ColdStorage	1	0	0
4	FlowBatteryEnergy	1	0	0
5	FlowBatteryPower	1	0	0
6	AbsChiller	1	0	0
7	AbsRefrigeration	1	0	0
8	PV	0	100	1
9	SolarThermal	1	0	0
10	EVs1	1	0	0
11	AirSourceHeatPump	0	0	0
12	GroundSourceHeatPump	1	0	0

Figure 40: Continuous technologies constraints

The obtained results are shown by Figure 41. Total annual energy costs savings of 21.5% were possible and CO_2 emissions lowered by 50% when compared to the reference case. The investment decisions are shown by Figure 43.

	Total Annual Energy Costs (k$)
Reference	245
Investment scenario (incl. annu	192.4
Total Savings (%)	21.5%
OPEX Savings (%)	59.8%

	Total Annual CO2 emissions (metric tons)
Reference	632.0
Investment scenario (incl. annu	314.6
Savings (%)	50%

Figure 41: Annual savings for costs and CO2 emissions for the outage scenario

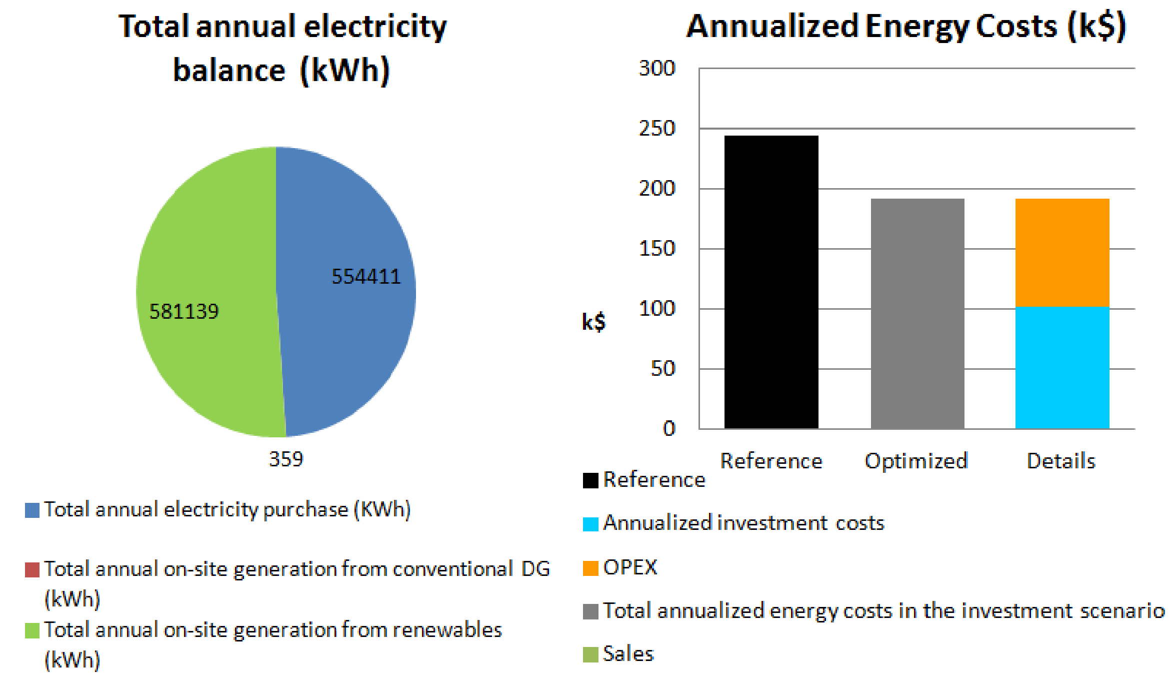

Figure 42: Annual costs and CO2 emissions savings

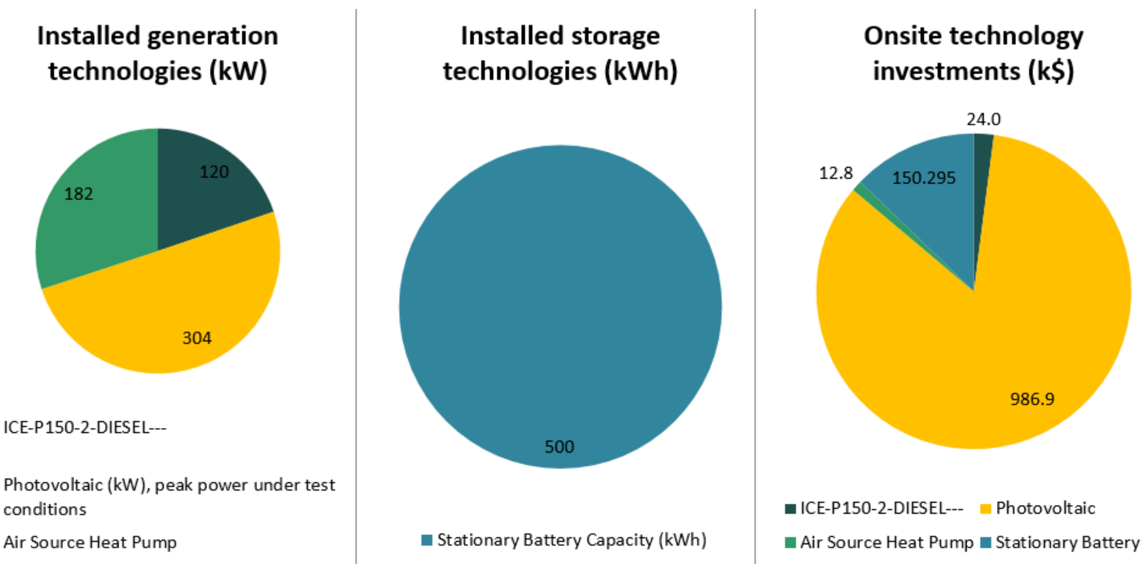

Figure 43: Investments capacities and upfront capital costs

No curtailment occurred as the new investments allow enough on-site generation to prevent them from happening (Figure 44).

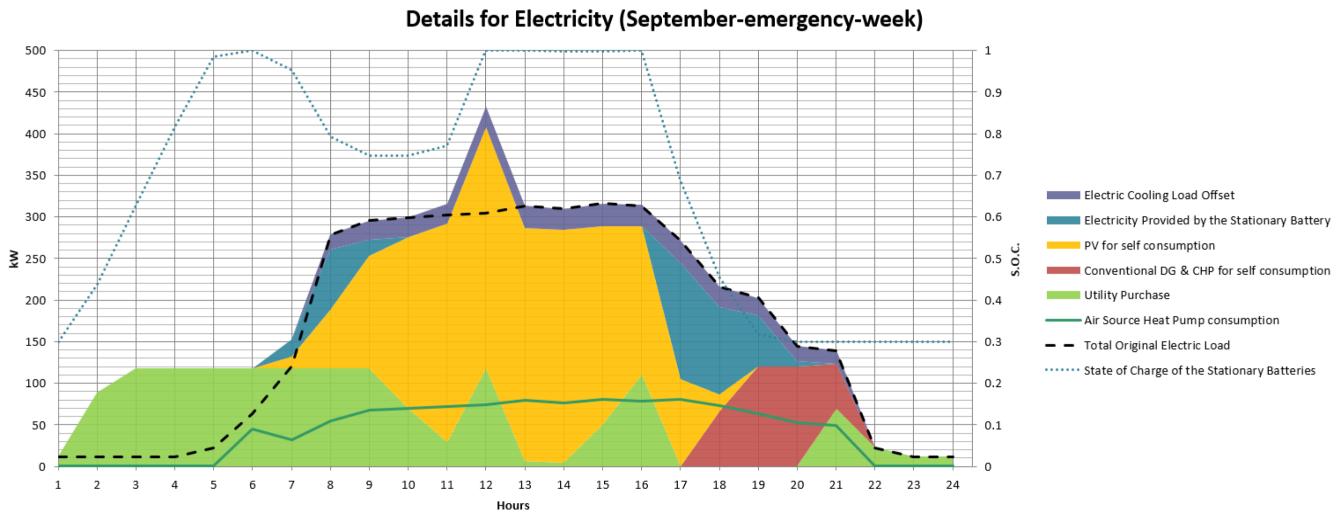

Figure 44: Electricity dispatch with outage

It can be seen that during the outage period the loads are mainly served by the stationary battery and internal combustion engine. It should be noted, however, that given the nature of the optimization algorithm, results are biased by foresight. In other words, as every time steps is solved simultaneously and is equally valued in the solution process, results reflect the anticipation of an outage, which will lead to an optimistic use of the battery. While this is a limitation of the current DER-CAM version, it is possible to minimize this effect by applying the battery cycling obtained in standard day-types to the end-use loads and re-adjusting the available battery size.